ASHBY & GEDDES
ATTORNEYS AND COUNSELLORS AT LAW
500 DELAWARE AVENUE
P. O. BOX 1150
WILMINGTON, DELAWARE 19899

TELEPHONE
302-654-1888
FACSIMILE
302-654-2067

23 January 2014

DR
alisa
Amy
Lisa
mark
Jo
Kevin
Connie

RECEIVED
2014 JAN 23 PM 2 06

VIA ELECTRONIC MAIL & HAND DELIVERY

Ms. Alisa Bentley
Commission Secretary
Delaware Public Service Commission
861 Silver Lake Blvd., Ste. 100
Dover, DE 19904

Re: *PSC Docket No. 13-115*

Dear Ms. Bentley:

Enclosed please find the original and ten (10) copies of STAFF'S POST-HEARING BRIEF TO THE HEARING EXAMINER in the above-captioned docket. Copies have been provided to the service list in the manner indicated.

Respectfully submitted,

James McC. Geddes / dlb

James McC. Geddes

Enclosures
JMcCG:dlb
cc: The Hon. Mark Lawrence (via e-mail & hand delivery; w/encls.)
Members of the Service List (via e-mail w/encls.)

{00824035;v1 }

BEFORE THE PUBLIC SERV

OF THE STATE OF

ORIGINAL

IN THE MATTER OF THE APPLICATION OF DELMARVA POWER & LIGHT COMPANY FOR APPROVAL OF A CHANGE IN ELECTRIC DISTRIBUTION RATES AND MISCELLANEOUS TARIFF CHANGES (FILED MARCH 22, 2013)	PSC DOCKET NO. 13-115

STAFF'S POST-HEARING BRIEF TO THE HEARING EXAMINER

Ashby & Geddes
James McC. Geddes (#690)
500 Delaware Avenue
P.O. Box 1150
Wilmington DE 19899
302-654-1888 (telephone)
302-438-9500 (cell phone)
302-654-2067 (fax)
jamesgeddes@mac.com

Julie M. Donoghue (#3748)
Deputy Attorney General
Delaware Department of Justice
820 N. French Street, 6th Floor
Wilmington, DE 19801
302-577-8348 (telephone)
jo.donoghue@state.de.us

Dated: January 21, 2014

{00824997;v1 }

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF DELAWARE

IN THE MATTER OF THE APPLICATION OF DELMARVA POWER & LIGHT COMPANY FOR APPROVAL OF A CHANGE IN ELECTRIC DISTRIBUTION RATES AND MISCELLANEOUS TARIFF CHANGES (FILED MARCH 22, 2013)	**PSC DOCKET NO. 13-115**

STAFF'S POST-HEARING BRIEF TO THE HEARING EXAMINER

Ashby & Geddes
James McC. Geddes (#690)
500 Delaware Avenue
P.O. Box 1150
Wilmington DE 19899
302-654-1888 (telephone)
302-438-9500 (cell phone)
302-654-2067 (fax)
jamesgeddes@mac.com

Julie M. Donoghue (#3748)
Deputy Attorney General
Delaware Department of Justice
820 N. French Street, 6th Floor
Wilmington, DE 19801
302-577-8348 (telephone)
jo.donoghue@state.de.us

Dated: January 21, 2014

TABLE OF CONTENTS

Page No.

TABLE OF AUTHORITIES

Cases

Statutes

Regulations

Other

INTRODUCTION

Apparently $65 million dollars in additional rates approved by this Commission over the last two and a half years is not enough for this utility -- it seeks more revenue relief from its weary ratepayers. Its appetite for spending seems to know no bounds; it certainly, as demonstrated in this case, is not limited by any self-constraint. And why should it be? With the regulatory calculus unable to keep up with Delmarva's prodigious spending, frequent rate cases seem to be the only way the Company can grow into its dividend.[1] And so Delmarva's ratepayers are asked to reach into their pockets -- once again -- to subsidize this extravagant spending behavior. Riding its dog-eared arguments that "we know best," or "in our professional judgment," etc., the Company seeks to bulldoze the applicable regulations, as well as specific promises it made to Staff and this Commission that it would pursue a different course.

Again, as in the last litigated case, Delmarva makes a mockery of the test year/test period concept and the matching principle by selecting an historic test period and then making a host of adjustments to it for events occurring months, even years after its ostensible end. Perhaps this is nowhere better reflected than in its brazen attempt to inflate its rate base for reliability investments going beyond the test period by more than a year. The Company can point to no Commission decision that would support such a manipulation of the test period concept, nor does it even try. Instead, it blatantly proffers that this adjustment is a known and measurable change, even though 32% of it is outside any known fact admitted in

---

[1] " 'Our Plan B is to keep rate cases every nine months if that's necessary, and that is what we plan to do' Anthony J. Kamerick, Pepco Holdings' Chief Regulatory Officer, told investors. 'I think we keep pounding the rate-cases drum.' " *The Washington Post* (August 7, 2012). *See also*, Tr. at 233, 257-8.

References to the exhibits introduced at the evidentiary hearings will be cited as "Exh. __ (Witness' Name) at ___" for direct testimony; "Exh. __ (Witness' name-R") at ___" for rebuttal testimony; "Exh. __" for non-testimonial exhibits. References to the transcript of the hearings will be cited as "Tr. at ___;" Delmarva's Post-Hearing Opening Brief "OB at. __."

this case. This cavalier representation of the facts is rather indicative of an imbalance that has crept into the last several cases in which the Company has asked for rate relief. This rate case is not prompted by the Company's actual needs as much as by its greed. This case is about the shareholders -- not the ratepayers. The Company is on a spending spree, spending millions of dollars on capital projects that are not required by any applicable Delaware law or regulation. As will be shown below, these projects are necessary to increase revenues and to sustain existing dividends, not to meet any reliability requirements in Delaware. Although the Company wraps its request in a purported need to sustain reliability -- to meet its own theoretical regulatory paradigm -- unwrapped it is nothing more than a naked demand for additional revenues surrounded by a patina of a purported need that does not exist -- at least not in Delaware.

In concert with its rate base approach, the Company proposes ratemaking treatments for various expenses that, if accepted, would guarantee it a full return *of and on* each expense. In fact it seeks to recover for expenses that occurred in prior periods before the test period even started! The Company seems determined to pile on as much risk as possible on to its ratepayers while denying those same ratepayers a commensurate reduction in the return on equity in exchange for shouldering the additional risk of guaranteeing recovery of the Company's expenses. As one witness in this proceeding stated, "Regulation is not intended to be a reimbursement system."[2]

This one-sided view of the regulatory universe is not acceptable and should not be supported by this Commission. The Company is entitled to the opportunity to earn a fair rate of return; the Supreme Court has said so. But it is not entitled to dollar-for-dollar recovery of every expense it incurs. Shareholders should be in this too; they should bear their fair share of

[2] Exh. 13 (Crane) at 19.

the risk if the Commission is to authorize a return in excess of the cost of debt. Staff asks the Hearing Examiner and this Commission to keep this in mind while considering the parties' contentions in this case.

Staff and the DPA made similar arguments in Docket No. 09-414 regarding the Company's test year manipulation. There the Commission correctly noted that it has the discretion to set the test year for a utility, but may not arbitrarily reject adjustments that are outside of it. But surely this Commission can recognize that by using only historical data, and allowing the Company to unilaterally decide what parts of the regulatory calculus (investments, revenues, expenses) that it can selectively adjust outside of that period, is unfair and can only lead to rates that are inflated, unjust and unreasonable. The Company willingly admits that it has made no adjustment to test period information for increases in customer revenues post 2012, but was also forced to disclose that revenues in the first quarter of 2013 grew at 3.5 percent.[3] This imbalance should not be allowed to continue.

Staff needs to remind the Hearing Examiner and the Commission that this is not the same case presented in Docket No. 09-414 when reliability investments were only extended five (5) months beyond the grant made by the Commission in the prior case, Docket No. 05-304. No, this time the Company is asking to extend that allowance (gift) even further. It has doubled the investment in reliability plant additions since the last case and stated that it has a corporate policy to have annual rate cases; to come back every year to ask ratepayers to pay more in rates. And for what purpose -- so the Company can grow into its dividend?[4]

---

[3] Exh. 34 at 20; Tr. at 253-4. The Company did make one adjustment in its rebuttal case to increase earnings as a result of an OBEP change. Exh. 20 (Ziminsky) Sch. (JCZ-R)-1 at pg. 2 of 5.

[4] In the last three and a half years, the Company has asked for over $100 million dollars in rate relief: (1) $28 million dollars in PSC Docket No. 09-414 (Application filed 9/18/09); $32 million dollars in PSC Docket No. 11-528 (Application filed 12/2/11); $42 million dollars in PSC Docket No. 13-115 (Application filed 3/22/13). Yet its dividend payout ratio remains one of the highest in the country and hovers above 90% percent of its retained earnings. Tr. at 233-234.

It is time to reset the table, to rebalance the interests of allowing the Company an opportunity to earn a fair rate of return on assets that are placed in public service, and are truly necessary to provide adequate service, and the ratepayer's interest in having fair and reasonable rates. That balance needs to be adjusted; the Company's avarice needs to be curbed.[5] The Commission should take this opportunity to rebalance the ratemaking calculus in Delaware. It has the chance to do so in this case.

[5] The Company's attitude toward regulation is well reflected in Mr. Rigby's comments regarding Delmarva's filing in Docket No. 13-384, which company officials stated, "will help them make more of the profits to which they are entitled." Exh. 35.

NATURE AND STAGE OF THE PROCEEDINGS

On March 22, 2013, Delmarva Power & Light Company ("Delmarva" or the "Company") applied to the Delaware Public Service Commission (the "Commission") for approval to: (1) increase base rates for electric distribution service by $42,044,000, a 23.8 % increase over existing distribution revenues;[6] (2) modify certain provisions of its tariff which included adding LED lighting options to its Outdoor Lighting (OL) tariff, and (3) proposing a new rider related to recovering costs associated with DelDOT relocation projects. With its application (the "Application"), the Company submitted the direct testimony of seven (7) witnesses: (1) Fredrick J. Boyle, Senior Vice President and Chief Financial Officer for Pepco Holdings, Inc. ("PHI"); (2) Robert B. Hevert, Managing Partner of Sussex Economic Advisors, LLC; (3) Michael W. Maxwell, Vice President Asset Management for PHI; (4) Jay C. Ziminsky, Manager of Revenue Requirements - Regulatory Affairs, PHI; (5) Marlene C. Santacecilia, Regulatory Lead in Rate Economics, PHI; (6) Kathleen A. White, PHI's Assistant Controller; and (7) Elliot P. Tanos, Manager, Cost Allocation, PHI.

On April 9, 2013, by PSC Order No. 8337, the Commission opened this docket to consider the Company's filing. The Commission's Order suspended the Application pending evidentiary hearings and a final decision concerning the justness and reasonableness of the proposed new rates, tariffs and rate design. The Commission authorized the Company, pursuant to 26 *Del. C.* § 306(c), to implement an annual $2.5 million dollars increase in intrastate operating revenues effective June 1, 2013, on an interim basis and subject to refund; waived the statutory bond requirement in connection with those interim rates; and waived certain Minimum Filing Requirements ("MFRs"). The Commission designated Mark Lawrence as Hearing

[6] Exh. 11 (Peterson) at 4.

Examiner and directed him to: (1) to schedule and conduct public comment sessions and evidentiary hearings necessary to produce a full and complete record concerning the justness and reasonableness of the proposed requested rates, proposed tariff changes and rate design; (2) submit proposed findings and recommendations to the Commission based on the record established in the proceeding; and (3) rule on intervention petitions and establish public notice requirements for the docket. The Commission established the intervention deadline as May 7, 2013, and instructed the Company to publish notice of its Application in *The News Journal* and *The Delaware State News*.

Hearing Examiner Lawrence granted petitions for leave to intervention filed by The Caesar Rodney Institute ("CRI") and the acting Public Advocate ("DPA") on April 11, 2013. The Hearing Examiner also granted the intervention petition filed by the Department of Natural Resources and Environmental Control ("DNREC").[7]

On April 16, 2013, Staff -- after reviewing the Company's Application indicating its intent to invest $397 million dollars in infrastructure improvements -- filed a motion requesting the Commission to open an investigation into the level of the Company's proposed future level of expenditures for reliability improvements set forth in Witness Maxwell's testimony. Delmarva opposed the creation of a separate docket to investigate its future reliability expenditures, contending instead that the reliability investments could be investigated in the existing docket. The Commission heard Staff's Motion, and Delmarva's opposition to Staff's request to open an investigation, on April 23, 2013. After hearing all interested parties, the Commission indicated it was inclined to open the investigation and subsequently an agreement was reached by Delmarva, Staff and the DPA on a proposed order opening an investigation

[7] *See* PSC Order No. 8376 (May 14, 2013).

docket to review Delmarva's planned distribution infrastructure and reliability investments five years into the future.

On May 7, 2013, Docket No. 13-152 was opened for the purpose of investigating the Company's proposed level of investment in distribution plant as set forth in Witness Maxwell's direct testimony in this matter and to consider whether Docket 50 reliability standards should be revised. [8]

Pursuant to his Commission-granted authority, the Hearing Examiner issued a procedural schedule establishing deadlines for intervention, discovery, and public comment sessions in all three counties, pre-filing of direct testimony by Staff and intervenors, and pre-filing of rebuttal testimony by the Company. Evidentiary hearings were set for November 13, 14 and 18, 2013.

On July 2, 2013, the Hearing Examiner granted the Petition for Leave to Intervene Out of Time filed by the Delaware Energy User's Group ("DEUG").[9]

Public Comment sessions were held in New Castle, Sussex and Kent counties on August 5, 8 and 13 respectively. Written public comments were due on August 20, 2013.

On August 16, 2013, Staff and intervenors prefiled direct testimony. Staff submitted testimony from David E. Peterson, Senior Consultant at Chesapeake Regulatory Consultants; Stephanie L. Vavro, Principal of Silverpoint Consulting LLC;[10] and Dr. Karl R. Pavlovic, Senior consultant, Snavely King Majoros & Associates, Inc. The DPA submitted testimony from Andrea C. Crane, a principal of The Columbia Group, Inc.; Dr. David E. Dismukes, Consulting Economist with Acadian Consulting Group; and David C. Parcell, Executive Vice President and

---

[8] *See, In the Matter of the Investigation Into Delmarva Power & Light Company's Planned Distribution Infrastructure Investments over the Next Five Years*, Docket No.13-152, PSC Order No. 8363 (May 7, 2013).
[9] *See* PSC Order 8411.
[10] Based on Staff's recommendation, Silverpoint Consulting LLC was hired by the Commission to provide consulting services in this docket and to lead the investigation on behalf of Staff and the Commission into the levels of future distribution infrastructure investments proposed by the Company in Witness Maxwell's testimony, the subject of Docket No. 13-152. *See*, footnote 4 *supra*.

Senior Economist with Technical Associates, Inc. DEUG submitted testimony from Nicholas Phillips, Jr., a managing principal with Brubaker & Associates, Inc. No additional testimony from the other intervenors was submitted.

On September 12, 2013, pursuant to 26 *Del. C.* § 306(b), Delmarva filed an application to implement under bond a cumulative interim rate increase of $27,655,265. After Staff's review, the Commission found that the application was consistent with the statutory provision that allowed, after seven (7) months from filing a proposed rate increase, for a utility to place into rates, temporarily and subject to refund with interest, 15% of its intrastate revenue and granted the Company's request.[11]

On September 20, 2013, the Company submitted prefiled rebuttal testimony from Messrs. Boyle, Hevert, Maxwell, Ziminsky, Tanos and Ms. Santacecilia. The Company reduced its requested rate increase to $38.976 million dollars from its original request of $42 million dollars. This was caused, in part, by a reduction in the level of forecast plant additions for 2013.

The evidentiary hearings were held on November 13 and 14, 2013, and continued and were completed on November 18, 2013.[12]

Pursuant to the amended procedural schedule, Staff's post-hearing brief is due to be filed on January 21, 2014. In accordance with that schedule, this is Staff's Post-Hearing Brief to the Hearing Examiner and the Commission.

---

[11] *See*, PSC No. Order 8466.

[12] On November 12, 2013, one day before the hearings began, Delmarva informed the parties of an alleged mistake in its deferred tax calculation when reviewing its schedules. Elimination of the "error" by Delmarva's calculation would have the effect of increasing the proposed revenue requirement by $705,151 (to $39,681,517) from its rebuttal position filed almost two (2) months before of $38.976 million dollars. The parties agreed to consider the merits of this issue outside the proposed schedule.

OVERVIEW OF THE PARTIES' RATEMAKING POSITIONS

The Company's Application to the Commission requests $42,043,757 or a 23.8% increase over existing retail distribution rates using a test period ending December 31, 2012.[13] Delmarva's request is premised primarily on $65 million dollars in plant reliability adjustments 12 months beyond the test period, inclusion of Construction Work in Progress ("CWIP"), and a proposed rate of return on common equity of 10.25%, resulting in a requested 7.53% return on rate base.[14] The Company subsequently revised its rate request to $39 million dollars, primarily because its forecasted plant closures for 2013 were overstated by over 20 percent, and, accordingly reducing its revenue requirement by over $3 million dollars.[15]

Staff calculates a revenue requirement of $11,442,413, based on a test period rate base of $578,744,304, an overall rate of return of 7.09% on the Company's capital structure, and test period pro forma operating income of $34,318,925.[16] The primary differences between the Company and Staff's positions are the use of average test period plant balances, removal of for post-test period reliability investments (pending conclusion of the Commission's investigation into the issue), removal of CWIP, and a lower return on common equity.

The DPA calculates a revenue requirement of $7,309,999, based on a test period rate base of $553,669,028, an overall rate of return of 7.09% on the Company's capital structure, and test period pro forma operating income of $34,970,408.[17] The primary differences between the Company and

---

[13] This is in addition to the $22 million dollars in additional distribution rates that were the product of a settlement in the last Delmarva rate proceeding based on a December 31, 2011 test period. See PSC Order No. 8265 (December 18, 2012).

[14] Exh. 5 (Ziminsky) at Sch. (JCZ – R)-1 at pg. 2 of 5.

[15] Exh. 20 (Ziminsky-R) Sch. (JCZ-R)-7 pg. 1 of 2; OB at footnote 237.

[16] Exh. 15 (Parcell) at 4; Exh.11 (Peterson) (DEP-1) Sch. 1, pg. 1 of 3. Staff relied on DPA witness Parcell in developing a suggested return on common equity for purposes of calculating its revenue deficiency. Staff has relied on Mr. Parcell's cost of equity recommendations for over 15 years in various utility matters.

[17] Exh. 13 at (Crane) at 4.

the DPA's positions are removal of post-test period reliability investments, CWIP, and Prepaid Pension and a lower return on equity common equity.

DEUG did not proffer an accounting or cost of capital witness in this proceeding, but did sponsor Mr. Phillips on cost of service and rate design issues.

recovery of normally incurred operating expenses is abuse of discretion, bad faith or waste.[19] Yet as the Company well knows that is not the standard applicable to issues involving capital investments --that standard is used and useful.[20] Having suggested the application of an incorrect standard upon which to review the issue of post-test period reliability investments, the Company moves on to suggest that exercising its professional judgment on what investments should be made, and when, ought to end any further discussion about the appropriateness of the recovery in rates of those particular investments. Again, the Company misstates the applicable law -- this Commission decides what investments are used and useful in providing electric service to ratepayers that it is charged by statute to protect, not the utility. The standard of used and useful is not met merely by the utility's opinion as to what is appropriate "in its professional judgment." Nor is Mr. Maxwell the oracle of what is the appropriate System Average Interruption Index ("SAIDI") measurement to meet the Commission determined reliability standard. Rather, the general principles of public utility law recognize that the "used and useful" standard requires that the plant included in rate base be reasonably necessary to the efficient and reliable provision of utility service to the public.[21] Thus, the Company's attempt to abrogate any Commission responsibility in the determination of these issues is quite clear, and quite wrong as a matter of law.

---

[19] *Delmarva Power & Light Co. v. Pub. Serv. Comm'n*, 508 A.2d 849, 859 (Del. 1986)("The law is well settled and not disputed as to the standard of review of the Commission and the burden of proof of a public utility with respect to the allowance of a utility's normal accepted operating expenses in the absence of a finding of waste, inefficiency or bad faith.")

[20] *Chesapeake Utilities Corp. v. Delaware Pub. Serv. Comm'n*, 705 A.2d 1059, 1071 (Del. Super. 1997); citing *Pub. Serv. Comm'n v. Diamond State Tel. Co.*, 468 A.2d 1285, 1290 (Del. 1983).

[21] *Pub. Serv. Comm'n*, 468 A.2d, 1290(citing *L. S. Ayres & Co. v. Indianapolis Power & Light Co.*, 169 Ind. App. 652, 351 N.E.2d 814, 833 (1976); *see also* 26 *Del. C.* § 102(3) which recognizes this principle in providing: "Any other element of property which, in the judgment of the Commission, is necessary to the effective operation of utility."

III. DELMARVA'S ANALYSIS OF REGULATION DOCKET 50 REQUIREMENTS IS CONFUSING, MISLEADING AND IRRELEVANT TO ANY ISSUE IN THIS PROCEEDING.

The Company attempts to protect the level of its investments in reliability plant for 2012 and 2013, as well as the timing of those investments, under the shroud of a Commission regulation docket often referred to as Regulation Docket 50.[22] The pertinent provisions of that regulation are two:

> *1.3 Compliance with this regulation is a minimum standard. Compliance does not create a presumption of safe, adequate and proper service. Each EDC needs to exercise their professional judgment based on their systems and service territories. Nothing in this regulation relieves any utility from the requirement to furnish safe, adequate and proper service and to keep and maintain its property and equipment in such condition as to enable it to do so.* 26 *Del. C.* § 209.
>
> *1.8 EDCs are required to explore the use of proven state of the art technology, to provide cost effective electric service reliability improvements.*

From these provisions the Company divines that it can regulate itself and infers that it can set its own standards unilaterally. Staff disagrees.

The Company's Brief suggests that the regulation provides:

1. Achieving a SAIDI of 295 minutes by itself "does not create a presumption" that Delmarva has met the requirement of providing "safe, adequate and proper service."

2. Delmarva's engineers and managers must exercise their "professional judgment based on their systems and service territories" to determine what level of reliability the Company should seek to provide to its customers.

3. Docket 50 mandates that Delmarva must remain vigilant in its efforts to use "state of the art technology" to provide actual "service reliability improvements.[23]

It further suggests that customers are not only entitled to reliable service, but that Delmarva must also provide "an appropriate level of enhanced reliability" service to its

---

[22] "Electric Service Reliability and Quality Standards" ("Regulation Docket 50") (effective September 10, 2006); now set forth in 26 *Del. Admin. C.* §3007 *et. seq.*
[23] OB at 9-10.

customers.[24] In Delmarva's lexicon, if the investments are "appropriate," they are "in full compliance with Delaware law."[25] Having created a standard of review that does not exist anywhere in the Delaware statute, the Company goes on to suggest why its reliability investments must be fully recoverable in this Docket. However, nowhere does the Company define what "appropriate" means in the context of Delaware's reliability standards or why such investments in reliability need to be made in 2013 versus 2014 or 2015. (See Chart below.)

Delmarva Delaware
2012 Expenditure
And
Five-Year Plan 2013-2017
Dollars in Millions[26]

Table 1

Distribution	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**Total 2013 Through 2017**
Customer Driven	$12.6	$12.1	$11.9	$12.1	$12.6	$13.0	**$61.7**
Reliability	$64.1	$71.4	$58.9	$59.2	$60.3	$59.2	**$309.1**
Load	$2.8	$4.3	$6.1	$4.2	$4.5	$7.4	**$26.6**
Total	**$79.5**	**$87.8**	**$76.9**	**$75.7**	**$77.4**	**$79.6**	**$397.4**

Staff agrees that the Company must exercise its professional judgment in providing safe, adequate and proper service consistent with the applicable Commission mandated reliability regulations. But that does not mean, as Delmarva presumes, that it gets to unilaterally decide what level of reliability to provide to its customers, or that the whole distribution grid needs to be improved to meet the needs of a few business customers that require "ultimate reliability."

[24] *Id.* at 10.
[25] *Id.*
[26] Exh. 4 (Maxwell) at 5.

In addition, in a telling omission, the Company fails to include in its synopsis of the regulation that reliability improvements are to be "cost effective."[27] The Commission's responsibility is to regulate public utilities to ensure safe and reliable service at just and reasonable rates. It is the Commission's job to define what that means. In the context of Regulation Docket 50 (the only applicable standard dealing with reliability issues), the Commission has anchored reliability improvements to cost effectiveness, a restriction that the Company fails to recognize.[28] Rather than being "hinged" to this regulatory constraint, the Company appears to believe that it can self regulate itself or spend whatever it wants on reliability projects either in 2012 or 2013, or beyond.

Furthermore, the Company has failed to meet its burden of proof that it could not provide safe, adequate and proper service to its customers without these dramatically escalating capital expenditures. It is the Company's burden -- not Staff's -- to establish that these investments are necessary, now, to meet the existing reliability standard in a cost effective manner. Was the Company not providing reliable service to its Delaware customers in 2008 when reliability spending was at $23.6 million dollars and its SAIDI at 213? How about 2009 when reliability spending was $25.9 million dollars; its SAIDI 190? Or 2010 when reliability spending was $29 million dollars -- SAIDI 199? Is the Company or Mr. Maxwell suggesting that it or he were not doing their jobs, after all Mr. Maxwell has had the same one since 2008 (Vice President of Asset Management) when these investment levels were deemed "appropriate" and the reliability measurements were being achieved. So the question that this Commission must ask is what has changed -- why now and why so much?

---

[27] *See*, 26 *Del. Admin. C.* §3007-1.8; OB at 9.
[28] OB at 10.

The only thing the Company can point to in its brief is Mr. Maxwell's "professional judgment." Repeatedly, Delmarva suggests that Mr. Maxwell's opinion counts most.[29] Yet, the Company never explains what is the appropriate reliability target that he and Delmarva are trying to meet and why. Instead, it appears from the Company's analysis that the resulting reliability target in any one-year is merely an output of the amount of money that Mr. Maxwell and Delmarva believe is appropriate to input into the Company's infrastructure. [30]

Mr. Maxwell suggests that in Delmarva's professional judgment that merely meeting the minimum SAIDI reliability standard contained in Regulation Docket No. 50 of 295 minutes would not satisfy Delmarva's obligation to its customers, nor meet their needs. One of the factors he bases this opinion on is the results from the customer satisfaction survey of the Delmarva customers. According to Mr. Maxwell, these customer surveys have consistently found that "the most important driver of satisfaction to Delmarva's customers is reliability: 'providing reliable electric service' and 'restoring outages when they occur.'"[31] But what is interesting to observe is that the Hearing Exhibit Mr. Maxwell relies on, Exhibit 83, shows a lower customer satisfaction for reliability -- now -- than before the Commission had reliability standards, and before the Company spent millions of dollars on reliability improvements. Clearly, this cannot be as an important a driver as the Company suggests since its marks for providing reliable service since 2001 have, on average, gone down in customers' minds -- not up.[32]

---

[29] OB at 11 to 18.

[30] Staff notes that this is a far different position than the one taken by the Company at the time the SAIDI standard was first established in Regulation Docket 50 when it opposed Staff's suggestion of a SAIDI of 241 on the basis that it was too stringent. *See, Letter to Bruce H. Burcat from Randall V. Griffin* (August 26, 2005), Appendix B.

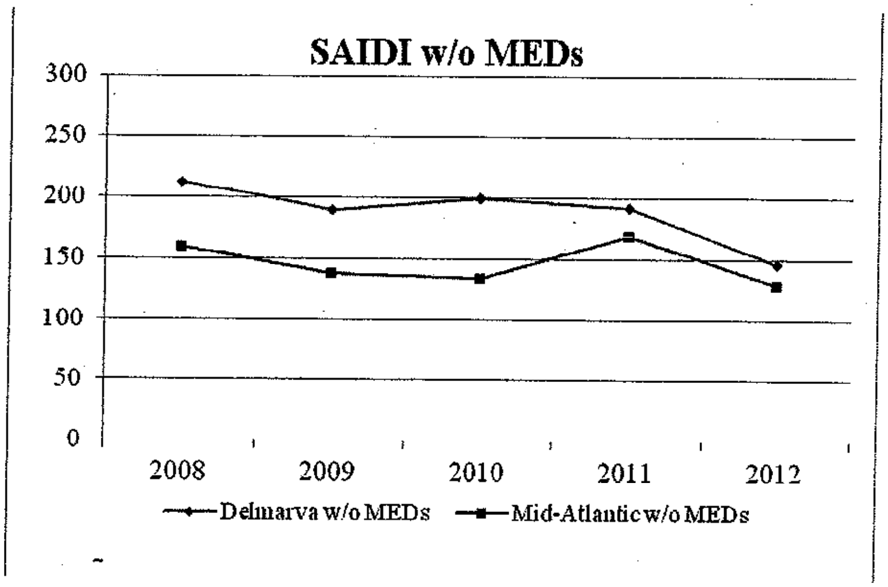
[31] OB at 17.

[32] Compare the average of 2001-2004 (87%) found at Tr. at 763 with Exh. 83, average for 2010-12 (85%).

It certainly can't support, as Delmarva suggests, the millions of dollars in additional capital being spent to meet a nonexistent reliability target. The record is devoid of any evidence of its attempt to limit investment costs in any meaningful way. The Company has provided no studies of cost effectiveness regarding any of its reliability investments it now seeks recovery in rates, and was forced to admit both at the hearings and in discovery that it had performed no such studies.[33] It suggests, however, that in the absence of such profligate spending on infrastructure, it would be in the 4th Quartile of all utilities.[34] But of course no party to this proceeding is recommending that the Company stay in the 4th Quartile, and Staff recognizes that Delmarva's SAIDI has come down after spending millions of dollars on reliability improvements. That is not the point. The issue is the amount being spent and the timing of those expenditures. Is it all needed now? There is no evidence in this record that it is.

Rather than comparing Delmarva's SAIDI ranking to the 106 utilities participating in the 2012 Institute of Electrical and Electronics Engineers ("IEEE") Survey, a more relevant comparison of where Delmarva's system performance ranks is to compare it to other electric utilities operating in the Mid-Atlantic region.[35] (See Chart below.)[36]

[33] When asked to provide such studies undertaken by the Company for the purpose of examining the cost versus the benefit or cost effectiveness of infrastructure investments as proposed in this proceeding and as planned for the next five years, Mr. Maxwell was forced to admit, "The requested analysis has not been done." Exh. 37; Tr. at 387. The Company chides DPA witness Dr. Dismukes for advocating cost-benefit analysis for reliability investments, arguing that Delaware law or regulations do not support it. OB at 63. The language of Section 1.8 implies otherwise -- that there is a burden on the utility to prove that the reliability improvements be cost effective. *Contra*, footnote 18, *supra*.
[34] OB at 17.
[35] *Id.* at 30-1.
[36] Exh. 86. "MED" stands for Major Event Days. The Chart excludes MEDs, consistent with the IEEE reporting.



Clearly Delmarva's performance on a system basis is comparable with other utilities in the region. As pointed out above, there is no basis on which to opine as to why the level of spending that was appropriate in 2008 through 2010, when Delmarva's SAIDI was in the 200 range must be substantially augmented and why it must happen now.

In fact, Delmarva's own planning documents indicate that it did not think it would achieve a SAIDI of 142 until 2016 -- three years after the close of this record. But it did achieve a 146 SAIDI in 2012. Obviously, the Company's "professional judgment" under forecasted the impact on its system reliability from investing an additional by $30 million dollars a year.[37] But that begs the question of why is the Company spending so much so quickly.

And it can't be because of more frequent storms as the Company suggests.[38] The SAIDI standard being discussed excludes major events such as Hurricane Sandy and the wind event on June 29, 2012, referred to as Derecho. Nor are those events being addressed in the Reliability Enhancement Plan initiated in Delaware in 2011.[39] There is no real initiative aimed at reducing outage time for individual customers in those situations. As Mr. Maxwell was forced to admit,

[37] Exh. 12 (Vavro), Appendix PSC-CP-2 Attachment A, at pg. 2.
[38] OB at 13-4.
[39] Tr. at 320.

the Customer Average Interruption Duration Index ("CAIDI"), which measures the length of time an individual customer suffers an outage, has not changed measurably since 2002; it remains around two (2) hours.[40] Thus, one's opinion about the severity of recent storms, and how Delaware has not suffered the way other Mid-Atlantic states have,[41] is not causally related to the question of what is an appropriate SAIDI level in Delaware.

Delmarva's criticism of Staff witness Varo is also misplaced. Ms. Vavro concluded that: (1) Silverpoint saw no engineering necessity for the reliability enhanced capital projects to maintain SAIDI at current levels; and (2) that by seeking rate base treatment for these capital investments --now -- the Company is essentially "putting the cart before the horse" given that the Company has no new performance standards to meet nor is there any framework or context within which to consider these additional investments. Thus, she concluded that the dramatic increase in reliability spending must be part of a broader corporate strategy, and certainly was not driven by the existing reliability standards found in Regulation Docket No. 50.[42]

As the Commission is well aware, the lack of any context for the review of reliability capital expenditures was the primary impetus behind the creation of Docket No. 13-152, which was opened to investigate Delmarva's proposed distribution infrastructure and reliability investments on a going forward basis. Based on Staff's concern that Delmarva may be investing more on infrastructure and system reliability improvements than is appropriate to meet the standards of Regulation Docket No. 50, the Commission in May 2013 opened the docket to investigate Delmarva's proposed distribution infrastructure and reliability investments going forward for a period of up to five (5) years and to consider whether the reliability standards set for Delmarva in Regulation Docket 50 should be revised to: "(1) include new or adjusted metrics

[40] Tr. at 365.
[41] Tr. at 354-5.
[42] Exh.12 (Vavro) at 12-14.

to help measure reliability performance as it relates to distribution infrastructure and reliability investment, and (2) indicate when and if such investment is consistent with Delmarva customers' reliability needs and the ability of those customers to pay for such investment."[43]

The Company opposed the opening of that Docket on the basis that the appropriate forum to review the costs of Delmarva's reliability investments in its electric distribution system was in a base rate case, and that the level of investment should be reviewed in its currently pending rate case. However, the Commission rejected the Company's position and determined it had the authority to open a docket to investigate Delmarva's proposed distribution infrastructure reliability investments going forward pursuant to its general regulatory jurisdiction over all public utilities.[44]

Rather than abide by the Commission's order in Docket No. 13-152, but consistent with its objection to the opening of any investigation into its reliability spending (which position the Commission rejected), the Company seeks to litigate in this case the appropriateness of its capital reliability investments for 2013 and beyond. But this is the very subject that Docket No. 13-152 was opened to review. Thus, Delmarva's whole argument of its entitlement to recover -- now -- reliability investments beyond 2012, the test period in this case, is misplaced and pre-empted by Docket No. 13-152 where that review will actually be made. By opening the investigation, the Commission has decided to review the necessity of those investments, as well as the timing of them there, in Docket No. 13-152, not here.

In this context, it appears anomalous that the Company would devote such a significant portion of its brief in trying to support its decision-making with regard to the selection of certain

[43] PSC Order No. 8363 (May 7, 2013), ¶ 2.
[44] 26 *Del. C.* § 201 et seq.

infrastructure investments necessary to meet "its reliability objectives."[45] These arguments may be persuasive when it comes time to consider them in Docket No. 13-152, and when other parties have the opportunity to weigh in on them, but they are not relevant to any issue in this case.[46]

Having set up the proverbial "straw-man" regarding issues that are not in this case, the Company proceeds to discuss at some length what Staff witness Vavro did or did not say in her testimony. Delmarva then sets up a series of false premises based on its misunderstanding of where these issues are going to be considered.[47] It is true that Ms. Varo did not provide any evidence that the Company failed to exercise "good judgment" in determining that reliability needed to be improved or any evidence that additional capital investments in reliability assets were needed to increase the reliability for Delmarva's customers.[48] Nor did she recommend any reduction in the level of investment in capital projects related to reliability or "challenge any of the reliability infrastructure investment initiatives made by Delmarva."[49] As she stated, her firm was not retained in the rate case to look at those issues. Silverpoint was, however, retained as the Commission's consultants to assist Staff in making those determinations in the investigation docket -- Docket No. 13-152.[50] That investigation is on going, and the issues raised about the level of investment and of Delmarva's exercise of its judgment in making those investments will be thoroughly reviewed in that docket.

[45] OB at 19-25.

[46] No party had an opportunity in this case to comment on any of the Company's four (4) initiatives since Mr. Maxwell and his counsel chose to introduce the details of them in Mr. Maxwell's redirect, rather than including such information in his rebuttal testimony in September. In essence the Company waited to try its case on these issues until after the testimony of other witnesses had been completed. *See e.g.*, OB, footnotes 59-63, 65-70.

[47] "Staff Consultant Failed to Offer Any Evidence That Delmarva Failed to Exercise Professional Judgment" in determining what reliability investment needed to be made, selection of those projects, the need to improve reliability, or the initiatives selected were appropriate. OB at 25-30.

[48] *Id.* at 25.

[49] *Id.* at 26.

[50] It should be noted that Ms. Varo's firm has been recently retained to represent the Maryland Commission as its consultant to review the long-term infrastructure improvement and storm restoration plans of all of the Maryland investor-owned utilities, including Delmarva. *See,* MD PSC Order 9298 (January 6, 2014).

IV. UNCONTESTED ISSUES AS BETWEEN STAFF AND DELMARVA.

The Company presented several adjustments that were not contested by the other parties to the proceeding. Not satisfied with the mere fact that these adjustments were not opposed in this Docket, the Company seeks some kind of imprimatur that these issues cannot be raised in future proceedings. Staff disagrees. Staff failure to take a position on some issues does not constitute any understanding between the parties, other than for the purposes of this proceeding those issues do not have to be resolved by the Hearing Examiner, or ultimately the Commission. Staff has limited resources and only raises issues in a proceeding that have importance for ratepayers in the context of the particular application or filing. In addition, the Commission does not always hire the same consultants in every proceeding, and thus Staff (as well as the Commission) is not bound in a precedential way by prior decisions based on the opinions of different consultants. Staff's decision not to contest a particular issue is just that -- nothing more. The Company's attempt to make more of this is nonsensical and should be rejected.[51] The uncontested issues in this proceeding based on the Company's Application are:

Earnings Adjustments

- Rate Change from Docket No. 11-528 (Adjustment No. 1);
- Weather Normalization (Adjustment No. 2);
- Bill Frequency (Adjustment No. 3);
- Injuries & Damages Expense Normalization (Adjustment No. 6);
- Uncollectible Expense Normalization (Adjustment No. 7);
- Remove Employee Association Expense (Adjustment No. 9);
- Removal of Executive Incentive Compensation (Adjustment No. 11);

[51] The incongruity of the Company's position is belied by its first footnote: "To the extent that the Company has not addressed any particular issue or position of any of the parties to this proceeding in this brief, it does not constitute agreement or disagreement with that position." *Compare*, OB at 1, footnote 1 with OB at 50.

- Removal of Certain Executive Compensation (Adjustment No. 12);
- Storm Restoration Expense Normalization (Adjustment No. 13);
- Pro-form Advanced Metering Infrastructure (AMI) O&M Expenses (Adjustment No. 17);
- Pro-form AMI O&M Savings (Adjustment No. 18);
- Pro-form AMI Depreciation & Amortization Expense (Adjustment No. 19);
- Normalize Other Taxes (Adjustment No. 25);
- Remove Qualified Fuel Cell Provider Project Costs (Adjustment No. 28);
- Remove Post 1980 Investment Tax Credit (ITC) Amortization (Adjustment No. 30);
- Removal of Renewable Portfolio Standards (RPS) Labor Charges (Adjustment No. 32); and

Rate Base

- Amortization of Actual Refinancing Costs (Adjustment No. 27).
- Removal of Pre-paid Insurance from Rate Base[52]

The impact of the uncontested issues is to increase Delmarva's earnings to $36,193,743 from $29,988,586 and rate base to $677,950,311 from $674,873,467.[53]

V. RATE OF RETURN

A. Introduction.

> *The appropriate cost of equity for the utilities that we regulate has always been one of the most difficult issues we consider in a rate case. Over the years we have repeatedly expressed our belief that the DCF equity model should be the model on which we primarily rely in establishing a utility's cost of equity.*[54]

[52] Witness Ziminsky in his rebuttal testimony agreed that Company's rate base should be reduced by the allowance for pre-paid insurance since it is measured in the lead/lag study, which is the basis for the working capital adjustment, and to include it in rate base would be counting it twice. Exh. 20 (Ziminsky-R) at 65.
[53] Exh. 20 (Ziminsky-R) Sch.1, at pg. 1 of 5.
[54] PSC Order No. 6930 at ¶ 269.

As the Commission noted in its last decision involving Delmarva, for more than 20 years it has primarily relied on one method to ascertain the appropriate equity costs for the utilities subject to its jurisdiction: the Discounted Cash Flow model ("DCF').[55] Although the Commission has indicated it considers other equity cost models in making its decisions on the appropriate cost of equity for a particular utility, under weighting the results of the DCF model is something it does not support.[56] Exact procedures for precisely determining the cost of equity (which must be estimated because it is an opportunity cost and is therefore prospective) have not been developed.[57] Several models (besides the DCF method) exist for estimating the cost of equity, such as the Comparable Earnings ("CE") method, the Capital Asset Pricing Method ("CAPM"), and the Risk Premium ("RP") method. Although each method differs from the others, all -- if properly employed -- can be useful in estimating the cost of equity.[58] But this Commission's preference for using the DCF model for calculating the appropriate or fair cost of equity for the utilities it regulates is quite clear.

Under economic principles, a fair rate of return normally means that an efficient and economically managed utility will be able to maintain its financial integrity, attract capital, and establish comparable returns for similar risk investments.[59] These concepts are derived from economic and financial theory and are generally implemented using financial models and economic concepts.[60]

As Mr. Parcell explains, an analysis of the seminal U.S. Supreme Court decisions of *Bluefield Waterworks & Imp. Co. v. Pub. Serv. Comm'n of W. Va.*, 262 U.S. 679, 43 S. Ct. 675, 67 L. Ed. 1176 (1923); *Allen v. St. Louis, I.M. & S. Ry. Co.*, 230 U.S. 553, 591, 33 S. Ct. 1030, 57 L.

---

[55] *Id.*; PSC Order No. 8011 at ¶ 284.
[56] PSC Order No. 6930 at ¶ 270.
[57] Exh. 15 (Parcell) at 7.
[58] *Id.*
[59] *Id.*
[60] *Id.*

Ed. 1625 (1913) (*Hope Natural Gas*), establish the three economic and financial parameters (i.e., comparable earnings, financial integrity, and capital attraction) reflect the economic criteria encompassed in the "opportunity cost" principles of economics.[61] The opportunity cost principle provides that a utility and its investors should be afforded an opportunity (not a guarantee) to earn a return commensurate with returns they could expect to achieve on investments of similar risk. The opportunity cost principle is consistent with the fundamental premise, on which regulation rests, namely, that it is intended to act as a surrogate for competition.[62]

As Staff has done many times in the past, it chose to rely on the testimony of Mr. David Parcell for its cost of capital recommendations. Mr. Parcell has testified in over 20 cases in Delaware, including four previous Delmarva cases. [63]

To support its cost of equity request, the Company turned to a relatively new face (and a more expensive one) in its effort to swell its proposed return on invested capital in Delaware -- Mr. Robert Hevert. Unlike Mr. Parcell who has filed testimony in numerous proceedings before the Commission, this is the first time that Mr. Hevert has had his testimony examined in this jurisdiction.[64]

B. Capital Structure.

As DPA witness Parcell indicated, the place to start in determining the cost of capital for a utility is with the development of an appropriate capital structure. In this case there were no issues raised involving the proposed capital structure. The Company proposed using its actual capital structure ratios as of December 31, 2012, of 50.78% long-term debt and 49.22% common equity.

---

[61] *Id.*
[62] *Id.*
[63] *See,* Footnote 16, *supra*. A list of his previous appearances in Delaware is attached as Appendix A to this Brief.
[64] Mr. Hevert filed testimony on behalf of Delmarva in both Docket Nos. 11-528 and 12-546, but since both matters were resolved before hearings, he did not appear in Delaware as a witness in an evidentiary proceeding in either case.

Witness Parcell used the Company's suggested capital structure percentages in developing his overall cost of capital analysis.[65] The Company did not propose to include any short-term debt in its capital structure.[66]

The Company's proposed capital structure uses an embedded cost of debt of 4.91% that reflects Delmarva's long-term debt costs as of December 31, 2012. Mr. Parcell used this debt cost in his analysis.[67]

The third and final step in determining the appropriate cost of capital for Delmarva is to estimate the cost of equity for the Company. To do this Mr. Parcell used three methodologies: (1) DCF; (2) CAPM; and (3) CE.[68] All of his models indicated that Delmarva's cost of equity should be lower than the stated return to which the Company agreed in resolving its last electric rate application -- 9.75%.[69] The results of his models are set forth below:

Methodology	Range	Mid-Point
Discounted Cash Flow	9.0%-9.4%	9.20%
Capital Asset Pricing Model	6.9%-7.0%	6.95%
Comparable Earnings	9.0%-10.0%	9.4%

Combining the three models, Mr. Parcell determined a proper equity cost for Delmarva (as explained below) to be between 9.20% and 9.50%, with the mid-point being 9.35%. He used this cost in recommending an overall cost of capital of 7.09% for the Company.[70]

C. DPA and Staff's Recommended Cost of Equity.

Because return on equity is a market-based concept but Delmarva is not a publicly-traded company,[71] it is a generally accepted practice to analyze groups of publicly-traded comparison or

[65] Exh. 15 (Parcell) at 3.
[66] Exh. 2 (Boyle) at 6-7; Sch. (FJB)-1.
[67] *Id.*
[68] Exh. 15 (Parcell) at 8. As Parcell explained in his testimony, he did not use the RP model in his analysis because his CAPM analysis is a form of the RP method.
[69] *See,* PSC Order No. 8265, at 2, ¶ 1.
[70] Exh. 15 (Parcell) at 4.

"proxy" companies with similar risk profiles to determine an appropriate cost of equity for the subject company.[72] As he has done in the past, Mr. Parcell selected his own proxy group using certain criteria to develop a comparison group.[73] In addition, he also examined Mr. Hevert's group and applied similar analyzes. The results of his three methodologies to determine a fair cost of equity are discussed below.

1. **DCF.** Mr. Parcell explained that the DCF model, one of the oldest and most commonly used models, is based on the "dividend discount model" of financial theory. The dividend discount model provides that the value (price) of any security is the discounted present value of all future cash flows.[74] Mr. Parcell used the constant growth variation of the DCF model and combined the current dividend yield for each of his proxy groups with several indicators of expected growth.[75] He recognized the timing of dividend payments and increases by making a quarterly compounding adjustment to the dividend yield component. For his price component he used the average of the high and low stock price for each company for the period May to July 2013.[76] This resulted in an average adjusted yield of 3.9% for his electric proxy group and the same 3.9% for the Hevert electric proxy group.[77]

Mr. Parcell then turned to the growth rate, which he called "the [DCF's] most crucial and controversial element." He testified that the objective of estimating this component is to reflect the growth expected by investors that is embodied in the price (and yield) of a company's stock.

[71] *Id.* at 17; Exh. 3 (Hevert) at 5.
[72] Exh. 15 (Parcell) at 19; Exh. 3 (Hevert) at 5.
[73] This group (ALLETE, Alliant Energy, Avista Corp., Black Hills Corp., IDACORP, MGE Energy, Northwestern Energy, Portland General Electric, TECO Energy, Westar Energy, Wisconsin Energy) met the following criteria: $1-10 billion market capitalization; electric revenues of 50% or greater; common equity ratio of 40% or greater; Value Line safety ranking of 1, 2 or 3; S&P stock ranking of A or B; S&P or Moody's A bond ratings; currently paying dividends; and not involved in a merger. Exh. 15 (Parcell) at 19-20 Sch. DCP-6.
[74] *Id.* at 20.
[75] *Id.* at 21.
[76] *Id.* at 22.
[77] *Id.* at Sch. DCP-7, pg. 4 of 4.

Since not all investors have the same expectations, it is important to consider alternative indicators in deriving their expectations. He examined five different indicators in his analysis:[78]

- 2008 to 2012 (5-year average) earnings retention (fundamental growth) as reported in Value Line;
- 5-year average of historic growth in earnings per share ("EPS"), dividends per share ("DPS") and book value per share ("BVPS") as reported in Value Line;
- 2013, 2014 and 2016 to 2018 projections of earnings retention growth as reported in Value Line;
- 2010 to 2012 projections of EPS, DPS and BVPS as reported in Value Line; and
- 5-year projections of EPS growth as reported in First Call.

Mr. Parcell summarized this information as follows:

	Mean	Mean	Mean Low[79]	Mean High[80]	Median Low[79]	Median High[80]
Proxy Group	8.1%	7.9%	7.0%	9.4%	6.7%	9.0%
Hevert Group	8.2%	8.0%	6.8%	9.0%	6.4%	9.1%

The results indicate average DCF cost rates of 7.9% to 8.2%, and high DCF rates between 9.0% and 9.4% on an average and mean basis.[81]

Based upon his analyses, and giving less weight to the lower values, Mr. Parcell concluded that 9.0% to 9.4% represented the DCF-calculated cost of equity for Delmarva, with 9.20% being the mid-point.[82]

2. **CAPM.** Mr. Parcell performed a CAPM[83] analysis for the same groups of companies in his DCF analysis. The general idea behind CAPM is that investors need to be

[78] *Id.* at 22-3.
[79] Using only the lowest growth rate.
[80] Using only the highest growth rate.
[81] *Id.* at 24.
[82] *Id.* at 25.
[83] Mr. Parcell testified that the CAPM, a variant of the RP method, describes and measures the relationship between a security's investment risk and its market rate of return. In his view, the CAPM is generally superior to the RP method because, unlike RP, the CAPM specifically recognizes the risk of a particular company or industry. Exh.15 (Parcell) at 25.

compensated in two ways: time value of money and risk. The time value of money is represented by a risk-free rate (usually tied to a U.S. Treasury instrument) and compensates the investors for placing money in any investment over a period of time. The other half of the formula represents risk and calculates the amount of compensation the investor needs for taking on additional risk. This is calculated by taking a risk measure (beta) that compares the returns of the asset to the market over a period of time and to the market premium (otherwise known as a risk premium) to make the investor consider investing in a more risky class of assets, such as stocks.

For the risk-free rate, Mr. Parcell used the three-month average yield from May to July 2013 for 20-year U.S. Treasury bonds, or 3.04%.[84] For the risk measure, he used the most current Value Line betas for each of his proxy group companies, noting that traditionally utility stocks have had betas below 1.0.[85] In this case, the betas for his proxy group ranged from 0.60 to 0.90.[86]

Based on this analysis, Mr. Parcell estimated the market risk premium component of the CAPM, which represents the expected return from holding the entire market portfolio. Technically, this reflects the return from holding the weighted combination of all assets (stocks, bonds, real estate, etc.); however, in utility rate proceedings, the traditional CAPM analysis focuses on the market return as the return on common stocks. Like the DCF's growth component, Mr. Parcell testified that investors do not universally share the same expectations regarding overall market return. Thus, there are alternative methods for estimating this component.[87]

[84] *Id.* at 26.
[85] *Id.* at 26-27.
[86] *Id.* and Sch. DCP-9.
[87] Exh. 15 (Parcell) at 27.

Mr. Parcell performed two measures of return for the S&P 500 Composite. First, he evaluated various averages of the equity return for this group from 1978 to 2012 (all available years reported by S&P). The average return deferential between yields on 20-year bonds and the S&P 500 (risk premium for investing in stocks) is about 6.6% over this period.[88] Second, he considered the total return for this group, as tabulated by Morningstar (formerly Ibbotson Associates), using both arithmetic and geometric means. Combining the total returns for the entire 1926 to 2012 period, he derived an arithmetic mean return of 11.8% and a geometric mean return of 9.8%. Based on this, he concluded that the expected total return for the S&P 500 was 10.8%. He also concluded that the expected risk premium is about 5.47% over the risk free rate, using the average of all three methods of determining market risk over U.S. Treasuries.[89]

Mr. Parcell's mean and median CAPM-derived equity costs were the same for his proxy group and for the Hevert group, 7.0% and 6.9% respectively. Thus, his CAPM results collectively indicated an equity cost of 6.9% to 7.0% for the proxy groups, which he used as a basis for concluding that Delmarva's equity costs were the same.

3. **CE**. Finally, Mr. Parcell also applied a CE method to estimate the Company's cost of equity. He testified that the CE method was derived from the "corresponding risk" standard of the *Bluefield Water Works*[90] and *Hope Natural Gas*[91] Supreme Court cases, and was based upon the opportunity cost concept.[92] According to Mr. Parcell, the CE method is intended to measure the expected returns on the original cost book value of similar risk enterprises. He testified that it provides a direct measure of the fair return because it translates the competitive principle upon which regulation rests into practice. It normally examines the experienced and/or

[88] *Id.* at 27, Sch. DCP-8.
[89] *Id.* at 28.
[90] *Bluefield Waterworks & Imp. Co.*, 262 U.S. 679.
[91] *Fed. Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591, 64 S. Ct. 281, 88 L. Ed. 333 (1944).
[92] Exh. 15 (Parcell) at 28-29.

projected returns on book common equity; this follows from the use of original cost rate base regulation for public utilities, which uses a utility's book common equity to determine the cost of capital. This cost of capital is then used as the fair rate of return applied to the book value of rate base to establish the dollar level of capital costs to be recovered. Thus, this method is consistent with the rate base methodology used to set utility rates. He noted that the CE analysis he employed is based upon market data (through use of market-to-book ratios) and is thus essentially a forward-looking market test. Consequently, he maintains that his CE analysis is not subject to the criticisms made by some who maintain that past earned returns do not represent the current cost of capital.[93]

In performing his analysis, and in an attempt to examine earnings over a diverse period of time, Mr. Parcell focused on three periods: 2009 to 2012 (the current cycle), 2002 to 2008 (the most recent business cycle) and 1992 to 2001 (the previous business cycle). He testified that a relatively long period of time is required for the analysis to determine trends in earnings over at least a full business cycle and to avoid any undue influence of unusual or abnormal conditions that may occur in a single year or shorter period.[94] His analysis demonstrated that historic returns on equity between 8.3% and 12.0% have produced market-to-book ratios of 120% to 170%.[95] Additionally, projected returns on equity for 2013, 2014, and 2016 to 2018 range from 8.8% to 10.0% for the proxy groups, which relate to market-to-book rations of 134% or greater.[96] Next, Mr. Parcell also examined the S&P 500 Composite group, which is comprised of "largely

[93] *Id.* at 29-30. According to Mr. Parcell, it is generally recognized that market to book ratios of greater than one (*i.e.* 100%) reflect positively a utility's ability to raise new equity capital without dilution and although there is no regulatory obligation to set rates to maintain such rations above one, it is an indicator of a fair cost of equity. *Id.* at 30.
[94] *Id.*
[95] *Id.* at 30 and Sch. DCP-10.
[96] *Id.* at 30.

unregulated" firms. He observed that over the periods studied, the S&P 500's earned returns ranged from 12.4% to 14.7% and its market-to-book ratios ranged from 204% to 341%.[97]

Mr. Parcell testified that the recent earnings of utilities and the S&P 500 can be used to indicate the level of return expected and achieved in the regulated and competitive sectors of the economy. To apply these returns to the cost of equity for electric companies, however, it is necessary to compare the risk levels of the electric utility industry with those of the competitive sector. Mr. Parcell's comparison demonstrated that the S&P 500 group is riskier than the utility comparison groups.[98]

From this analysis, Mr. Parcell concluded that the Company's cost of equity under the CE method is no greater than 9.0% to 10%. Given the recent returns and resulting market-to-book ratios, he testified that a return on equity of between 9.0% and 10% should result in a market-to-book ratio of at least 100%.[99]

D. Summary of Staff Results of Analyses.

Mr. Parcell's analysis produced the following results:[100]

Method	Calculated Rates	Mid-point
DCF	9.0% to 9.4%	9.20%
CAPM	6.9% to 7.0%	6.95%
CE	9.0% to 10.0%	9.50%

Mr. Parcell's three analyses indicate a cost of equity ranging from 6.9% to 10.0% for the electric utility industry. In determining his recommended cost of equity for Delmarva, Mr. Parcell testified that he focused on the higher end of his equity cost results, which already reflect the

[97] *Id.* at 32 and Sch. DCP-11.
[98] *Id.* at 32 and Sch. DCP-12.
[99] *Id.* at 32-33.
[100] *Id.* at 33.

upper range of fair returns. Based on his equity cost results and those factors, Mr. Parcell testified that Delmarva's fair cost of common equity is in the 9.2% to 9.5% range,[101] and so he recommends the mid-point of 9.35% for Delmarva.[102] He observes that his recommendation exceeds the mid-point of his DCF analyses and therefore implies use of only the highest growth rates.[103]

Mr. Parcell also explained why his CAPM produced suggested costs of equity substantially lower than his other methodologies (i.e., the DCF and CE methods).[104] First, risk premiums are lower now than they were in previous years. This shows a decline in investor expectations of equity returns and hence the premium required for an investment in stocks versus U.S. Treasury bond rates. Second, interest rate levels on the U.S. Treasury bonds (i.e., the risk-free rate) have been lower in recent years because the Federal Reserve System's policy has been to stimulate the economy by reducing interest rates. Although many believed this decline in U.S. Treasury yields was temporary, interest rates have remained low and continue to be historically low. Thus, low interest rates (and low CAPM results) are not temporary, but rather reflect investors' current expectations. As Mr. Parcell concluded, the CAPM results at the very least indicate that capital costs continue at historically low levels. Hence, Delmarva's cost of equity should likewise be lower than in prior years.[105]

Mr. Parcell also reviewed his recommendation to ensure that it would provide the Company with a sufficient level of earnings to maintain its financial integrity. He satisfied this criterion by calculating a pre-tax coverage if Delmarva earned his recommended rate of return

[101] Id.
[102] *Id.* at 3.
[103] *Id.* at 19-21.
[104] *Id.* at 34.
[105] *Id.*

and compared that to S & P's benchmark ratios for A-rated utilities.[106] He concluded that his recommendation would result in a coverage level within the benchmark range for an A-rated utility.

E. The Company's Proposed Cost of Equity and Capital Structure.

Mr. Hevert testified on behalf of Delmarva and provided both a recommendation on its cost of equity[107] and an assessment of the capital structure to be used for ratemaking purposes.[108] According to Mr. Hevert, Delmarva's current cost of equity is in the range of 10.25% to 11.00%.[109] Within that range, Mr. Hevert believes that a proposed return on equity of 10.25% is reasonable and appropriate, lies at the low end of the range of current equity costs, and is therefore reasonable "if not conservative."[110] As for Delmarva's proposed capital structure, he concludes that the Company's 49.22% common equity and 50.78% long-term debt is consistent with the capital structures at comparable operating utility companies for the past several fiscal quarters and thus is reasonable and appropriate.[111]

Although the proper method to perform an analysis of Delmarva's cost of equity is (1) to develop an appropriate capital structure, (2) to determine the embedded cost of long-term debt, and (3) to calculate the cost of equity,[112] Mr. Hevert begins his analysis by focusing on the selection of his proxy groups and his methodologies for determining his return on equity recommendation.[113] Then he discusses specific business risks that he alleges directly bear on Delmarva's cost of equity, the current capital market conditions and his view of their effect on

---

[106] *Id.* at 35 and Sch. DCP-13.
[107] Mr. Hevert stated that the cost of equity for a company is also called return on equity or "ROE." Exh. 3 (Hevert) at 2.
[108] *Id.*
[109] In Mr. Hevert's Rebuttal Testimony, he revised his former return on equity range of 10.25% to 11.00% to a new range of 10.25% to 10.75%. See Exh. 18 (Hevert-R) at 2.
[110] Exh. 3 (Hevert) at 2; Exh. 18 (Hevert-R) at 2-3.
[111] Exh. 3 (Hevert) at 2-3.
[112] Exh. 15 (Parcell) at 3.
[113] Exh. 3 (Hevert) at 3-5.

Delmarva's cost of equity, the reasonableness of Delmarva's proposed capital structure, and finally his summarized conclusions.

Mr. Hevert relies on four methodologies to determine his return on equity recommendation: his "DCF" model,[114] the CAPM model, "RP" model,[115] and a Multi-Stage form of DCF model.[116] He then chose what he deemed to be an appropriate proxy group by starting with companies classified by Value Line as electric utilities (which includes 49 domestic utilities) and applying certain screening criteria. He excluded companies that do consistently pay quarterly cash dividends, excluded companies whose regulated operating income over the three most recently reported fiscal years represented less than 60.0% of combined income; excluded companies whose regulated electric operating income over the three most recently reported fiscal years represented less than 90.0% of total regulated operating income; eliminated companies that are currently known to be a party to a merger or other significant transaction; and eliminated from his initial proxy group Edison International because, among other reasons, it recorded a loss from placing a subsidiary into Chapter 11 bankruptcy and divesting certain subsidiary assets.[117] Mr. Hevert alleges that all of the companies in his proxy group have been covered by at least two utility equity analysts[118] and have investment grade senior unsecured bond and/or corporate credit ratings from S&P.[119] He also included vertically integrated utilities in his proxy group because even though Delmarva is a transmission and distribution company, he alleged that there

[114] The constant growth DCF model is the most common variant of the DCF model and assumes that dividends are expected to grow at a constant rate. Exh. 15 (Parcell) at 20.
[115] Exh. 3 (Hevert) at 3.
[116] Mr. Hevert testified in his rebuttal that he used this fourth model in response to Parcell's testimony. Exh. 18 (Hevert-R) at 2.
[117] Exh. 3 (Hevert) at 7-8.
[118] *Id.* at 7.
[119] *Id.*

are no "pure play" state-jurisdictional electric transmission and distribution companies that may be used as a proxy for Delmarva's Delaware electric distribution operations.[120]

Mr. Hevert further explained that he estimated the return on equity using analyses based on market data to "quantify a range of investor expectations of required equity returns."[121] Mr. Hevert alleges that the key consideration in determining the return on equity is "to ensure that the overall analysis reasonably reflects investors' view of the financial markets in general and the subject company (in the context of the proxy companies) in particular."[122] To calculate the dividend yield component of the DCF model, Mr. Hevert used the proxy companies' current annualized dividend and average closing stock prices over the 30-, 90-, and 180-trading day periods as of February 15, 2013.[123] He then adjusted the dividend yield to account for periodic growth in dividends by assuming that dividend increases will be evenly distributed over calendar quarters.[124] Based on this assumption, he calculated the expected dividend yield by applying one-half of the long-term growth rate to the current dividend yield.[125]

Mr. Hevert also used the average daily closing prices for the 30-, 90-, and 180-trading days ended February 15, 2013, for the term Price Ratio and the annualized dividend per share as of February 15, 2013, for the Dividend Input.[126] He then calculated the DCF results using each of the following growth terms: The Zack consensus long-term earnings growth estimates, the First Call consensus long-term earnings growth estimates, and the Value Line long-term earnings

[120] His proxy group includes: American Electric Power Company, Inc., Cleco Corp, Empire District Electric, Inc., Great Plains Energy, Inc., Hawaiian Electric Industries, Inc., IDACORP, Inc., Otter Tail Corp., Pinnacle West Capital Corp., PNM Resources, Inc., Portland General Electric Co., Southern Company, Westar Energy, Inc. *Id.* Sch. (RBH)-1 pg. 1 of 3.
[121] Exh. 3 (Hevert) at 10.
[122] *Id.* at 10.
[123] *Id.* at 11-12. According to Parcell, there are several methods that can be used for calculating the dividend yield component. Exh. 15 (Parcell) at 21. In addition, these methods generally differ in the manner in which the dividend rate is employed (i.e., current versus future dividend, or annual versus quarterly compounding of dividends). *Id.*
[124] Exh. 3 (Hevert) at 12.
[125] *Id.* at 12 (citing Schedule (RBH)-1).
[126] *Id.* at 13.

growth estimates.[127] Next, he calculated the high and low DCF results,[128] and then he made adjustments to the growth rates in his DCF analyses.[129] Finally, he did not give any weight to the Mean Low DCF results when he developed his return on equity range and recommendation.[130]

Next, Mr. Hevert used a CAPM method to calculate the return on equity for the proxy companies.[131] For the CAPM model, he used two different estimates of the long-term risk-free rate: The current 30-day average yield on 30-year Treasury bonds (i.e., 3.12%) and the near-term projected 30-year Treasury yield (i.e., 3.25%).[132] This was because he asserted that utilities represent long-term investments. Mr. Hevert noted that he had concerns about using the CAPM method based on current market conditions.[133] His concerns related to the risk-free rate as represented by the yield on long-term U.S. Treasury securities, which he believes is being pushed down by two factors: The increasing equity market volatility and the Federal Reserve's policy of maintaining low long-term interests rates for U.S. Treasury securities.[134] Mr. Hevert also asserts that capital markets continue to change "quite significantly"[135] and that the Equity Risk Premium tends to move in the opposite direction as changes to the interest rates occur.[136] Thus, Mr. Hevert asserts that the CAPM results can be relatively volatile.

In calculating his return on equity based on the CAPM method, Mr. Hevert used two forward-looking estimates of the Market Risk Premium. For both CAPM methods, however, he

[127] *Id.*
[128] *Id.*
[129] *Id.* at 13 to 14.
[130] *Id.* at 14.
[131] *Id.* at 15.
[132] *Id.* at 17.
[133] *Id.* at 16.
[134] Mr. Hevert explained that because investors allocate their capital to low-risk securities (such as U.S. Treasury bonds) when equity market volatility increases, the yield on those securities will decrease (because investors "bid down" the yield). Exh. 3 (Hevert) at 16. In addition, since the 2008 Lehman Brothers bankruptcy filing, the Federal Reserve has maintained low long-term interest rates for U.S. Treasury securities. *Id.* Hence, Hevert asserts that even if investors were to invest more capital in risky assets, the Federal Reserve's policy may continue to maintain low Treasury yields. *Id.*
[135] *Id.*
[136] *Id.* at 17.

used beta coefficients from Bloomberg and Value Line for each of the proxy group companies.[137] For his first CAPM method, Mr. Hevert used the market required return, less the current 30-year Treasury bond yield.[138] For the market-required return, Mr. Hevert calculated the average return on equity based on the DCF model using data from Bloomberg and Capital IQ, respectively. For both of these, he calculated the average expected dividend yield (using the same one-half growth rate assumption he used earlier) and combined that amount with the average projected earnings growth rate to arrive at the average DCF results. Then he subtracted the current 30-year Treasury yield from that amount to arrive at the market DCF-derived ex-ante Market Risk Premium estimate.[139]

Mr. Hevert's second approach to the CAPM method uses market-based data to determine whether investors expect future risk to be higher (given that investors require higher returns for higher risk), lower, or approximately equal to historical levels.[140] When market risks are higher than historical levels, Mr. Hevert asserts that the Market Risk Premium would be higher than historical levels (and vice versa). He asserts that this second approach to the CAPM method relies on the Sharpe, which is the ratio of the long-term average Risk Premium for the S&P Index to the risk of that index.[141] Next, he then concludes that his calculation shows the expected Market Risk Premium is determined by investors' historical required return per unit of risk (the historical Sharpe Ratio) times the expected market risk.[142] Mr. Hevert explains that he used the 30-day average of the Chicago Board Options Exchange's ("CBOE") three-month volatility index and the average of the settlement prices over the same 30-day period of futures on the

[137] *Id.* at 19.
[138] *Id.* at 17.
[139] *Id.* at 17 -18.
[140] *Id.* at 18.
[141] Exh. 3 (Hevert) at 18. Mr. Hevert notes that the Sharpe Ratio is "relied upon by financial professionals to assess the incremental return received for holding a risky (i.e., more volatile) asset rather than a risk-free asset. *Id.* at 18 fn. 14.
[142] *Id.* at 19.

CBOE's one-month volatility index for July 2013 through September 2013. Mr. Hevert asserted that both of the indices used by him are market-based and observable measures of investors' expectations regarding future market volatility.

Mr. Hevert believes that his CAPM results fail to provide a reasonable range of return on equity estimates "at the time" because the low results are approximately 100 basis points below the lowest return on equity ever authorized for an electric utility in at least 30 years.[143] He therefore asserts that the mean low results simply are not reasonable. In addition, he believes that the Federal Reserve's policy on interest rates (as it affects Treasury yields) decreases the CAPM estimates "rather substantially."[144]

For the RP model, Mr. Hevert explains that this method estimates the cost of equity as the sum of an Equity Risk Premium and a bond yield. Mr. Hevert asserts that the Equity Risk Premium is the difference between the historical cost of equity and the long-term Treasury yields. Because this analysis is for electric utilities, Mr. Hevert believes that using actual authorized returns for electric companies as the historical measure of the cost of equity is a reasonable approach. Mr. Hevert then defines the RP as the difference between authorized returns on equity and the then-prevailing level of long-term (i.e., 30-year) Treasury yield. He then gathered data from 1,392 electric utility rate proceedings[145] and calculated both the average regulatory lag period and the average 30-year Treasury yield over the average lag period (which he found to be approximately 201 days).[146] Because Mr. Hevert believes that the analytical period includes interest rates and authorized returns on equity that are quite high during one period and quite low during another, he used the semi-log regression analysis which expresses

[143] *Id.* at 20.
[144] *Id.* at 21.
[145] These proceedings were between January 1, 1980, and February 15, 2013. *Id.* at 21-22.
[146] *Id.* at 22.

the Equity Risk Premium as a function of the natural log of the 30-year Treasury yield.[147] He also used a regression analysis in which the observed Equity Risk Premium is the dependent variable and the average 30-year Treasury yield is the independent variable.[148]

Mr. Hevert believes that over time, a statistically significant, negative relationship between the 30-year Treasury yield and the Equity Risk Premium has existed. Thus, he concludes that simply applying the long-term average Equity Risk Premium of 4.39% would significantly understate the cost of equity and produce results "well below any reasonable estimate."[149] He therefore arrives at an implied return on equity between 10.23% and 10.76% based on the RP method.

Despite using four different return on equity methods to arrive at a range of rates that should be acceptable, Mr. Hevert then argues that additional factors must be used to establish a reasonable range for the cost of equity.[150] He then includes an analysis of Delmarva's size (a "small size premium") and its flotation costs associated with equity issuances.[151] After analyzing these additional factors, Mr. Hevert asserts that a size premium as high as 178 basis points "is expected for Delmarva,"[152] but does not propose any specific adjustment for this factor. He then modified the DCF calculations and makes a "flotation cost adjustment" of 0.15% to provide a dividend yield that would reimburse investors for the issuance costs.[153] Again, Mr. Hevert "considers this" but does not recommend this adjustment.

F. Mr. Hevert's Recommendations on the Cost of Equity are Anomalous and Must be Rejected.

[147] *Id.* at 22 -23.
[148] *Id.* at 22.
[149] *Id.* at 23.
[150] *Id.* at 24.
[151] *Id.* at 24 and 26.
[152] *Id.* at 25.
[153] *Id.* at 26.

in making their individual investment decisions. Furthermore, it may not even be the same analyst for each individual company that Mr. Hevert is relying on since he picks only the highest estimate for his individual company analysis. In looking at Mr. Hevert's Schedule (RBH-1), which shows his constant growth DCF analysis, his "High ROE" only considers one of the earnings growth rate (reflected in columns [5], [6], and [7]), not three. Stated another way, the "High ROE" calculation only relies on one data point for earnings per share growth rate, and it may not be the same analyst making the projection for each member of the proxy group.[157] Thus, Mr. Hevert is using only one data point -- always the highest -- among the various EPS growth rate indicators to influence (and drive upwards) his growth rate calculation in his DCF.

"Cherry picking" financial information to drive a DCF analysis in a particular direction (although it is consistent with his client's manipulation of historic test period information) is not the type of analysis that this Commission has historically relied on -- nor should it rely on such distorted information in this case. Mr. Hevert further compounds his myopic drive to raise the DCF values by using only analysts' EPS forecasts of growth, ignoring alternative measurements of growth rates in his constant growth DCF model. This again tends to drive his DCF values up. Mr. Parcell's Exhibit 15 updated Mr. Hevert's DCF analyses using the same three sources of EPS projections for proxy companies. Exhibit 15 shows much lower values for DCF cost rates, as shown below:

	DCF Results	
Growth Rate	Average	Median
Zacks	9.20%	9.19%
First Call	8.98%	9.29%
Value Line	9.59%	9.08%

[157] *Id.* at 37.

Also as noted by the Maryland Commission, the inclusion of companies with substantially disparate growth rates that are markedly higher than Delmarva's is not appropriate either.[158] As Mr. Parcell suggested, Mr. Hevert's analysis is again influenced -- upwardly -- by inclusion of two companies in his composite group: Otter Tail Company and PNM Resources, both of whom have growth rates that far exceed that of the remainder of the Hevert proxy group (12% and 21.50% respectively).[159] By just removing those two companies from Mr. Hevert's analysis, the resulting DCF values fall within the range suggested by Mr. Parcell.

Regarding Mr. Hevert's CAPM analyses, Mr. Parcell found his risk premium values to be inflated. Mr. Hevert used:

Sharpe MRP	6.03%
Ex Ante Bloomberg MRP	9.88%
Ex Ante Capital IQ MRP	9.81%

Compared to actual investment return differential between common stocks and government bonds since 1929, Mr. Hevert's values greatly exceed the historical results of 5.4%.[160] Yet, he provides no explanation why investors would expect such a large increase in risk premiums over historic levels.

Mr. Hevert also used a Risk Premium approach to boost his recommended return on equity.[161] He began by comparing allowed return on equity for electric utilities and 30-year Government Bond yields since 1980. His historical results showed a long-term average equity risk premium of 4.39%, which, when using his current Treasury yield of 4.12%, would result in a return of under 8%. Unsatisfied with that low result, he applies regression analysis to arrive at his

[158] See Maryland Commission Decision in Case No. 9286, Order 85028 (July 20, 2012) at 107.
[159] Exh. 15 (Parcell) at 40-41. Otter Tail and PNM Resources also have negative growth rates based on the last five years, so it is unlikely the levels reflected in the Hevert proxy group are sustainable over time. *Id.* at 41.
[160] *Id.* at 41-42.
[161] As Mr. Parcell noted earlier, the RP method assumes the same risk premium for all companies exhibiting similar bond ratings. *Id.* at 25-26.

overstated conclusion that the implied equity returns based on this analysis should be between 10.23% and 10.76%. Based on Mr. Hevert's schedules, and attempting to reach the low end of his range, Mr. Hevert has to use a risk premium value of 7.11%, which is not anchored in any way to historical returns over the last 85 years.[162] As Mr. Parcell points out, average authorized returns for electric utilities have not been as high as 10.23% since 2010 and not as high as 10.76% since 2003.[163]

Notably, Mr. Hevert was the Company's Cost of Capital witness in the last case Delmarva electric case (Docket No. 11-528). For that docket, Mr. Hevert filed his initial testimony in December of 2011 when Treasury bond yields were at historic lows.[164] There, he recommended a rate of return on common equity of 10.75%, or 50 basis points higher than what he is now recommending in the current proceeding. Here, he points to rising interest rates as a reason to increase a utility's rate of return and suggests that somehow rising interest rates increase the risk of investing in utilities stocks.[165] Yet his recommendation is lower in this case than in the preceding one, where interest rates were at an all time low and the Company accepted a return on equity of 9.75%. Furthermore, although he acknowledged in his testimony that the models (presumably the DCF model) have returned lower recommended rates for common equity,[166] he recognizes this fact by simply lowering the top end of his range but not moving his proposed ROE of 10.25%.[167] This is of course because as stock prices have increased, the dividend yields have gone down while growth rates have stayed relatively flat, resulting in lower DCF values.

[162] Exh. 3 (Hevert) Sch. (RBH-5) pg. 1.
[163] Exh. 15 (Parcell) at 42.
[164] The benchmark 10-year yields on Treasuries ended the year below 2%, the lowest they had been since 1977. Wall Street Journal, December 30, 2011; http://online.wsj.com/article/BT-CO-20111230-706654.html.
[165] Exh. 18 (Hevert-R) at 8; Tr. 433-4.
[166] Exh. 18 (Hevert) at 2 ("I recognize that other model results have decreased since I filed Direct Testimony.")
[167] *Id.* at 2.

In summary, the same criticisms the Maryland Commission has leveled at Mr. Hevert and his analysis are just as applicable here. Although he noted in his direct testimony that the Supreme Court has recognized a fair rate of return on equity should be "comparable to returns investors expect to earn on other investments of similar risk," Mr. Hevert's analyses for determining the cost of equity in this proceeding are not premised on companies with comparable risks.[168] The group of utility companies Mr. Hevert has selected deviate from the standard he initially set. In addition, he has relied on single data points to achieve his desired goal in raising his expected cost of equity when interest rates are lower than they have been in over 60 years. Moreover, if the current market conditions continue, the costs of equity for a utility (such as Delmarva) should remain low. Such conditions justify reliance on Mr. Parcell's analysis of Delmarva's cost of equity based on a DCF model that recognizes a fair rate of return for Delmarva while still maintaining its ability to attract investors.

In contrast to Mr. Hevert's distorted application of factors to manufacture a return on equity that does not comport with reality, the return that Mr. Parcell recommends will allow investors in Delmarva to earn an appropriate return, particularly in this economic climate. Delmarva owns no generation, is solely a distribution company, has no competition and serves a heavily residential customer base, which is stable and unlikely to relocate. Thus, the economic risk to Delmarva is low. Evidence in the record indicates that Delmarva's parent company, PHI, has been able to raise $450 million dollars of capital over the last 12-18 months without harming its credit rating.[169] Staff's suggested return of 9.35% on equity will enable the Company to attract necessary capital and meet its statutory requirements of providing safe and reliable service to its customers despite the currently low interest rate environment. As it has on numerous

[168] Exh. 3 (Hevert) at 3.
[169] Tr. at 266.

occasions before, Staff supports and relies on Mr. Parcell's recommended cost of equity for Delmarva of 9.35% and an overall return of 7.09%.

Because Delmarva's parent has indicated it will seek rate increases more frequently, the time horizon for ratemaking is shorter than would normally be expected. In addition, the Federal Reserve has indicated it will continue to maintain low interest rates into the future, which will keep borrowing costs low.[170] Hence, the Hearing Examiner and the Commission should adopt Mr. Parcell's recommendations for a return on equity of 9.35%, which is based on comparable earnings in Mr. Parcell's proxy group and which, as shown above, would provide Delmarva with both financial integrity and sufficient capital attraction.

Overall Rate of Return Summary.

DPA and Staff's overall rate of return of 7.09% is comprised of the following:[171]

	Capital Structure by Percentage	Cost Rate	Weighted Return
Long-term Debt	50.78%	4.91%	2.49%
Common Equity	49.22%	9.20% to 9.50%	4.53% to 4.68%
Total	100%	7.02% to 7.17%	7.09% = Mid-Point

VI. TEST PERIOD RATE BASE ISSUE

Average vs. Year-End Rate Base.

In a change from its most recent Delaware electric filing (Docket No. 11-528), the Company seeks to move away from using an average rate base on which to calculate its rate request to an end of test period one, that it then inflates by forecasting reliability plant

170 "The Committee is maintaining its existing policy of reinvesting principal payments from its holdings of agency debt and agency mortgage-backed securities in agency mortgage-backed securities and of rolling over maturing Treasury securities at auction. Taken together, these actions should maintain downward pressure on longer-term interest rates, supporting mortgage markets, and help to make broader financial conditions more accommodative…" Federal Reserve Press Release, (September 18, 2013). http://www.federalreserve.gov/newsevents/press/monetary/20130918a.htm.
171 Exh. 15 (Parcell) at 2.

investments through 2013. The Company explains this change in test year philosophy in just three (3) lines of testimony from a witness who has never testified on the subject before.[172] "I propose the use of year-end, not average, rate base as the year-end rate base better reflects the assets which will be serving customers during the rate effective period for which rates in this proceeding are being established."[173]

In contrast, Staff witness Peterson explained and illustrated why an average rate base better captures the relationship between earnings and expenses and the investment in plant that is actually used to provide service during the same period.[174] When plant balances are growing, as they are here for Delmarva, using year-end rate base overstates the revenue deficiency by understating the income capacity of the existing rates. In Mr. Peterson's illustration, plant that is added at the end of the year in the last month, December, should not be added to the total plant balances (annualized) in calculating a return for the whole year since it was only used and useful in the last month of the year.[175] The potential impact on earnings is quite dramatic as show in Mr. Peterson's bank illustration. Thus, using year-end plant balances causes ratepayers to pay more in rates than is necessary to compensate the Company for its actual cost of service during a 12-month test period. To avoid this imbalance (a distortion according to Mr. Peterson), and the resulting understatement of Delmarva's pro forma earnings for the test period, Mr. Peterson recommends that the Hearing Examiner and the Commission set Delmarva's revenue requirement as is has in the past -- using an average rate base.[176] By using an average rate base,

---

[172] In Docket Nos. 11-528 and 09-414, Mr. VonSteuben was the Company's accounting witness dealing with test year/test period concepts.
[173] Exh. 5 (Ziminsky) at 33.
[174] Exh. 11 (Peterson) at 9-10.
[175] _Id._ at 10.
[176] _Id._

occasions before, Staff supports and relies on Mr. Parcell's recommended cost of equity for Delmarva of 9.35% and an overall return of 7.09%.

Because Delmarva's parent has indicated it will seek rate increases more frequently, the time horizon for ratemaking is shorter than would normally be expected. In addition, the Federal Reserve has indicated it will continue to maintain low interest rates into the future, which will keep borrowing costs low.[170] Hence, the Hearing Examiner and the Commission should adopt Mr. Parcell's recommendations for a return on equity of 9.35%, which is based on comparable earnings in Mr. Parcell's proxy group and which, as shown above, would provide Delmarva with both financial integrity and sufficient capital attraction.

Overall Rate of Return Summary.

DPA and Staff's overall rate of return of 7.09% is comprised of the following:[171]

	Capital Structure by Percentage	Cost Rate	Weighted Return
Long-term Debt	50.78%	4.91%	2.49%
Common Equity	49.22%	9.20% to 9.50%	4.53% to 4.68%
Total	100%	7.02% to 7.17%	7.09% = Mid-Point

VI. TEST PERIOD RATE BASE ISSUE

Average vs. Year-End Rate Base.

In a change from its most recent Delaware electric filing (Docket No. 11-528), the Company seeks to move away from using an average rate base on which to calculate its rate request to an end of test period one, that it then inflates by forecasting reliability plant

[170] "The Committee is maintaining its existing policy of reinvesting principal payments from its holdings of agency debt and agency mortgage-backed securities in agency mortgage-backed securities and of rolling over maturing Treasury securities at auction. Taken together, these actions should maintain downward pressure on longer-term interest rates, supporting mortgage markets, and help to make broader financial conditions more accommodative..." Federal Reserve Press Release, (September 18, 2013). http://www.federalreserve.gov/newsevents/press/monetary/20130918a.htm.
[171] Exh. 15 (Parcell) at 2.

investments through 2013. The Company explains this change in test year philosophy in just three (3) lines of testimony from a witness who has never testified on the subject before.[172] "I propose the use of year-end, not average, rate base as the year-end rate base better reflects the assets which will be serving customers during the rate effective period for which rates in this proceeding are being established."[173]

In contrast, Staff witness Peterson explained and illustrated why an average rate base better captures the relationship between earnings and expenses and the investment in plant that is actually used to provide service during the same period.[174] When plant balances are growing, as they are here for Delmarva, using year-end rate base overstates the revenue deficiency by understating the income capacity of the existing rates. In Mr. Peterson's illustration, plant that is added at the end of the year in the last month, December, should not be added to the total plant balances (annualized) in calculating a return for the whole year since it was only used and useful in the last month of the year.[175] The potential impact on earnings is quite dramatic as show in Mr. Peterson's bank illustration. Thus, using year-end plant balances causes ratepayers to pay more in rates than is necessary to compensate the Company for its actual cost of service during a 12-month test period. To avoid this imbalance (a distortion according to Mr. Peterson), and the resulting understatement of Delmarva's pro forma earnings for the test period, Mr. Peterson recommends that the Hearing Examiner and the Commission set Delmarva's revenue requirement as is has in the past -- using an average rate base.[176] By using an average rate base,

[172] In Docket Nos. 11-528 and 09-414, Mr. VonSteuben was the Company's accounting witness dealing with test year/test period concepts.
[173] Exh. 5 (Ziminsky) at 33.
[174] Exh. 11 (Peterson) at 9-10.
[175] _Id._ at 10.
[176] _Id._

rather than year-end, Delmarva's rate base is reduced by approximately $41 million and its revenue deficiency is significantly decreased.

VII. OTHER RATE BASE ISSUES

A. Reliability Closings -- Adjustment 26.

The Company's proposal to include an adjustment in its rate base for post-test period reliability projects should be rejected for numerous reasons.

1. Forecasted Plant Closings Up To A Year After The Test Period Should Not Be Included In Rates.

The adjustment to include in rate base a forecast of post-test year plant additions 12 months beyond the close of the test period creates a mismatch between plant investment and the revenues and expenses that flow from those investments. The result, as Mr. Peterson pointed out, drives earnings and the return on invested capital down while inflating the rate base for investments that do not match the test period revenues or expenses used to calculate the revenue deficiency.[177] This overstates Delmarva's actual revenue deficiency and revenue requirement.

The Company has also distorted the test period relationship between plant in service and other elements of the Company's revenue requirement. This is apparent when looking at the accumulated reserve for depreciation and deferred taxes. While Delmarva recognizes the increasing reserve for depreciation associated with post-test period reliability plant additions, it completely ignores the growth in the depreciation reserve for embedded plant that will be occurring as reliability plant is placed in service in 2013. Plant-in service during 2012 will continue to accumulate depreciation in 2013, which will reduce Delmarva's net investment in

[177] Exh. 11 (Peterson) at 12.

rate base. However, this reduction in rate base is not accounted for in the Company's rate base calculation, as Mr. Ziminsky was forced to admit during the hearings.[178]

Also, the Company failed to annualize the effects on the deferred tax reserve arising from bonus tax depreciation on non-reliability plant closings in 2013. These adjustments would have a positive effect (reduce) test period rate base, and thereby the revenue requirement, if the proper adjustments had been made.

Although the Commission permitted the inclusion of some post-test period plant in the last electric case that it considered, it did so specifically "under the circumstances of ... [that] case."[179] In the past, Delmarva has traditionally used average plant balances to develop its rate base claims. In the current case, it changed its methodology and used end-of-test year balances, making its rate base more prospective than those used in prior cases. Yet in neither case, this one or the prior case, has the Company made any adjustment to reflect increases in the number of customers or usage that would help to offset increased revenue requirements associated with new plant. Also, Delmarva in its prior electric rate case did not request post-test year adjustments that were purely speculative; it filed its rebuttal testimony a full three (3) months *after* the last date of the requested post-test year plant additions.[180] In this case Delmarva filed its rebuttal testimony three (3) months *before* the last date of the requested post-test year plant additions. Thus, the facts underlying Delmarva's request here are not the same as in its prior case. There is no Commission decision that the Company can point to, including Docket No. 09-414, that supports its position. This one-sided attempt to manipulate and create an asymmetrical test period upon which to base rates should be rejected.

---

[178] Tr. at 610-11.
[179] *See*, PSC Docket No. 09-414 at ¶ 60.
[180] *Id.* at ¶ 12.

2. The Company Made A Commitment, With Which It Failed To Comply, To Work To Develop Metrics For Approval of Reliability Projects Going Forward.

In Delmarva's last filed rate case, it based its request for rates on an average rate base using a test year ending June 2012 and a test period ending December 31, 2012. The parties resolved the Company's request for additional revenues of $31,760,741 on the eve of hearings in July 2012 for $22 million dollars. A settlement agreement ("the Settlement Agreement") was signed and submitted to Hearing Examiner Ikwuagwu in August 2012. The Commission approved the Settlement Agreement in December 2012, the last month of the test period for which Delmarva is basing rates in this case. As part of that Settlement Agreement, Staff specifically negotiated for a recognition by the Company that future reliability additions must be subject to some kind of metrics so that customers could better understand what benefits they were receiving from Delmarva's increasingly large additional investment in plant.

The Company agreed to work with Staff and other parties to establish such metrics for the reporting and approving of reliability projects going forward. Specifically, the Company agreed to meet and discuss these metrics.[181] Yet, the Company appears to have forgotten about this term of the Settlement Agreement it signed; the witnesses Delmarva presented in this proceeding certainly had. Neither chief policy witness Mr. Boyle, nor Mr. Maxwell (the "expert" on reliability investments), had any knowledge of any meeting in which the Company discussed internally or externally metrics to quantify future reliability investments.[182] Mr. Boyle had to admit that although he read the Agreement, his direct testimony did not accurately capture

[181] Para. 17 of Settlement Agreement (August 12, 2012), Exh. A, PSC Order No. 8265 (December 18, 2012) in PSC Docket No. 11-528.
[182] *Id.* Exhibit "A", ¶ 17; Tr. at 310-11.

what the terms of the Agreement were and the Senior Vice-President and Chief Financial Officer could not remember any follow-up related to the Company's commitment.[183]

In December 2012, the Commission accepted the Settlement Agreement -- and all of the parties commitments made therein -- as a basis to resolve the prior case. Less than three (3) months later, the Company sought $70 million dollars in new reliability investments with no metrics by which to judge whether they were used or useful. Furthermore, the Company had held no meetings in the interim to discuss such metrics and their relationship to this new investment.[184]

Delmarva's agreement to help develop metrics for the future approval of such capital investments create circumstances very different from those upon which the Commission made its decision in the last Delmarva litigated case Docket No. 09-414. As the Commission specifically stated in Docket No. 09-414, it was deciding a case under the circumstances presented there. Further, it was "also persuaded that those plant additions were necessary to preserve the reliable operation of the distribution system."[185]

No such finding can be made in this case. Not only did the Company promise to try and develop metrics with Staff's participation prior to seeking approval of future reliability investments, but this Commission opened a docket specifically to investigate Staff's contentions that the investment in reliability plant might be excessive and beyond the actual needs of its ratepayers.[186] Mr. Boyle admitted that the language of the Settlement Agreement meant to him "that the parties would get together and discuss metrics for reporting and approving the

---

[183] Tr. at 270-71.
[184] Tr. at 271.
[185] PSC Order No. 8011 at ¶60.
[186] Docket No. 13-152.

reliability projects going forward.[187] Further, he thought this would be done in the reliability docket.[188]

The Company is under a continuing obligation to comply with the Settlement Agreement that it previously entered into to resolve PSC Docket No. 11-528. Before it seeks to recover millions of dollars of reliability investments contained in Adjustment 26, this Commission should demand that the Company comply with the terms of the Settlement Agreement. It states that it reflects a "balancing of various issues and positions," that it must be approved in its entirety, and that "the terms of this Settlement will remain in effect until changed by an order of the Commission."[189] Staff is aware of no attempt made by the Company to request the Commission to reconsider its Order approving the prior settlement. Delmarva has benefited by the additional $22 million dollars in rates resulting from the Settlement Agreement, but the ratepayers have not benefited from the development of any metrics prior to the Company's request seeking recovery of new reliability investments.[190] The Commission should not validate the Company's failure to discuss reliability metrics by permitting consideration of post-test period reliability investments here. Furthermore, there is no need to decide whether the post-test period reliability investments are actually used and useful since this will be a subject of the Docket No. 13–152 investigation.

3. The Post-Test Period Investments Are Not Required To Meet The Applicable Delaware Reliability Standard.

Staff's testimony clearly pointed out that the Company is spending more on reliability investments than it needs to. As witness Maxwell admitted in the hearings, Delmarva began to

[187] Tr. at 270.
[188] *Id.*
[189] Settlement Agreement (August 17, 2012), Exh. A, PSC Order No. 8265.
[190] There is nothing now that would prevent the Company from, as promised, sitting down with Staff and discussing compliance with this paragraph of the Settlement Agreement. If as Mr. Boyle suggests, the Company is waiting to do this as part of the reliability investigation, it supports Staff's position that these post-test period adjustments to rate base must await the determinations made in Docket No. 13-152.

ramp up its expenditures for reliability after its sister company Pepco was fined in Maryland for failure to provide reliable service in the summer of 2010.[191] Because of the Maryland Commission's mandated requirement to improve reliability in that state, the Company began its relentless drive to spend money on plant investments in Delaware.[192] Yet there is no similar finding or requirement in Delaware made by this Commission, which requires Delmarva to take on a similar effort or commitment.[193] Rather, the standard that the Company needs to meet here was set in 2006 and reaffirmed in February 2013 as a SAIDI of 295.[194]

As Ms. Vavro pointed out in her testimony for the five years preceding the test period in this case, the Company has been maintaining a SAIDI average of around 200, or about 32% below the target set in Regulation Docket No. 50. (See Chart below).

Delmarva Delaware
Reliability-related Plant Additions and SAIDI Performance[195]

	Non-REP ($ millions)	REP ($ millions)	SAIDI (minutes)
2007	15.7		197
2008	23.6		213
2009	25.9		190
2010	29.0		199
2011	29.9	$11.6	192
2012	37.0	$26.5	146

Obviously the Company in "its professional judgment" saw no need to increase spending on capital projects to improve upon its reliability measurement in Delaware until after Pepco was fined in Maryland in 2010. But as the Company admitted, the increased spending in "Delmarva" Maryland in an effort to comply with the Maryland Commission's increasingly stringent

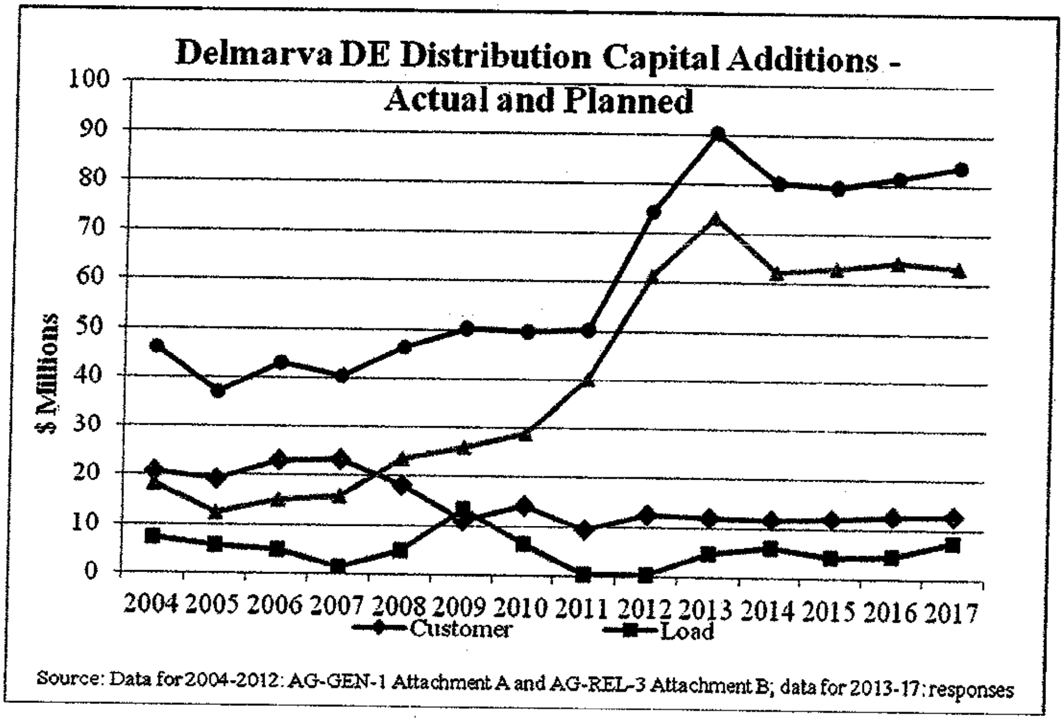
[191] Mr. Maxwell states that The Reliability Enhancement Program ("REP") came about as a result of the Maryland Commission's investigation into Case No. 9240. Tr. at 320, 322.
[192] Tr. at 330.
[193] "We were not in jeopardy of missing the target in Delaware ... we has some issues [with RMA] in Maryland." Tr. at 327
[194] 26 *Del. Admin. Code*. § 3007 *et. seq.*; PSC Order No. 8285 (February 7, 2013).
[195] Exh 12 (Varvo) at 12.

reliability standards is being replicated here in Delaware with no such Commission directive. There is no standard, rule or regulation in existence in Delaware that requires Delmarva to keep spending money to reach a target that it already exceeds by 50%.[196] In fact in the "December 2012 Performance Metrics and Report," "Delmarva" Delaware was not specifically discussed, while the efforts of its sister utilities to meet Maryland guidelines was highlighted.[197] Thus in this context, one must ask why Delaware ratepayers must now pay for something that clearly is not necessary to meet any applicable Delaware reliability regulations. And why is the Company asking them to?

The answer of course is found in the PHI corporate directive to build its asset base as a means to grow its earnings and maintain its dividend payout to its stockholders.[198] Thus, as mentioned before, this case is not about ratepayers' interests, but those of the owners of Delmarva's parent -- PHI. And the means to that end -- to sustain the dividend -- is to grow its asset base on the backs of its ratepayers with annual rate filings and a "pedal-to-the-metal" approach to reliability-related capital spending. (See Chart below).[199]

---

[196] Tr. at 239.
[197] Exh. 12 (Vavro), Appendix, Response to AG-REL-19.
[198] *See generally*, Exh. 34 at 10.
[199] Exh. 39.



Staff believes this corporate philosophy is wrong –at least in Delaware. There is no need to rush the level of these investments into rate base in this case when there is no target that the Company is trying to meet. As Staff explained, there is little or no framework, or guidelines, within which the parties in this proceeding can judge the usefulness of these investments.[200] That is why shortly after receiving this filing, Staff immediately moved for the Commission to open an investigation into what the appropriate level of investment should be given the existing standards in Delaware. It should not be the Company's unfettered right to make such decisions -- the Commission should have some say as well if only to establish some balance between shareholders' cravings for dividends and ratepayers' actual needs. The recovery of these reliability investments -- at least those that are a part of the Commission's investigation (2013-2017) -- should await the conclusion of that proceeding; they are not part of the case currently pending.

[200] *Id.* at 14.

4. The Cases Delmarva Cites In Support Of Adjustment 26 Apply The Wrong Standard And Are Inapposite.

Delmarva suggests that contrary to Delaware law and recent Commission decisions, Staff and the DPA have raised challenges to the post-test period adjustments that rely strictly on adherence to test period principles. Of course, that is not correct. The arguments that both Staff and the DPA have raised in their respective testimonies have little to do with (1) the avoidance of frequent rate cases, (2) the standard for expense recovery, or (3) the investments occurring shortly after the end of a test period. Rather, Staff and the DPA base their objections to the inclusion of the 2013 reliability investments on completely different grounds.

The facts in this case are unique. The Company is for the first time seeking recovery of capital investments made a full 12 months after the test period closed, a test-period it alone chose. These same investments are the subject of a separate investigation by this Commission. Testimony in this case showed that the Company could meet the existing Delaware reliability standards with less capital investment. This testimony supports Staff's argument that the unchecked level of reliability spending by the Company appears to be in place only to support a corporate policy to increase revenues.[201] These are some of the reasons why the cases cited by the Company to support Adjustment 26 are inapposite; they are based on different facts and have no relevance to the issues presented here for resolution.

The 1975 Delaware Superior Court case cited by the Company suggests that the Commission should not arbitrarily ignore later information where it would increase the likelihood of more frequent rate cases.[202] But those are not the facts underlying Staff's objection to Adjustment 26, nor does it take into account the fact that the Company is committed to filing annual rate cases. Staff's objection to the recovery of these expenses is that they are being

[201] Exh. 12 (Vavro) at 14; Exh. 35.
[202] *Application of Delmarva Power & Light Co.*, 337 A.2d 517, 518 (Del. Super. 1975).

included in this case rather than awaiting a future Commission decision or the conclusion of Docket No. 13-152.[203]

The three Commission decisions cited by the Company are also factually inapt. The Commission's decision in Docket No. 95–73, dealt with an issue concerning equipment that was going to be placed in service shortly after close of the test period.[204] Here, we have a situation where the Company is proposing to place in service equipment that will be closed to plant not shortly after the end of the test period, but rather 12 months later. In addition, some of the equipment is forecasted, and all of it is the subject of an ongoing Commission investigation.[205] The issue of known and measurable discussed in Docket No. 91-20, and more recently in Docket No. 09-414, is not the only issue here. The primary question is whether the post-test period reliability investments are necessary to provide adequate, safe and proper electric service at reasonable rates. Again, that issue will be resolved in Docket No. 13-152 -- not here. Accordingly, the inclusion of the post-test period reliability investments included in Adjustment 26 should await the results of the investigation proceeding.[206]

B. The Commission Should Follow its Prior Decisions and Exclude CWIP From The Company's Rate Base.

Delmarva's proposed that its test period rate base be augmented to include more than $70 million dollars of construction work in progress ("CWIP") that had not been closed to plant in

[203] Tr. at 257.

[204] *In Matter of the Application of Chesapeake Utilities Corp for a General Increase in Natural Gas Rates*, PSC Docket No. 95-73 (Filed April 4, 1995).

[205] The Company adjusted its forecasted post-test period plant reliability additions downward by $8.5 million dollars or 13%, only six (6) months after its initial filing. Exh. 20 (Ziminsky-R) Sch. (JCZ-R)-1 at pg. 2 of 5.

[206] Nowhere does the Company address the fact that if its reliability adjustment -- Adjustment 26 -- was granted in this case, including that portion that is not now known or measurable, and the Commission were to subsequently find in Docket No. 13-152 that some or all of the proposed reliability investment for 2013 was not used or useful at this time, or its inclusion in rate base should be delayed, how the Commission could implement such a decision regarding plant already in rate base. See cases cited in footnote 18 *supra*.

service by the end of December 2013 (i.e., 12 months past the end of the test period).[207] This one issue inflates the Company's revenue requirement by almost $8 million dollars. [208] The Company claims that these projects were "technically complete," were providing service to customers, and simply had not been transferred to plant; however, these projects would therefore theoretically be providing service before a decision is rendered by the Commission in this proceeding. The Company further claims that the amount of allowance for funds used during construction ("AFUDC") associated with the CWIP is substantially lower because routine distribution-related projects typically have shorter construction periods and thus lower dollar values.[209]

Both Staff witness Peterson and DPA witness Crane rejected the Company's adjustment to include CWIP in rate base on the grounds that the CWIP was not used and useful in providing service to customers during the test period.[210] Ms. Crane pointed out that the inclusion of CWIP violates the regulatory principle of intergenerational equity by requiring current ratepayers to pay a return on plant that was not providing them with service.[211] Mr. Peterson further observed that although the Company had made an adjustment to include CWIP in rate base, it had not made corresponding adjustments to reflect the revenue-enhancing and/or expense-reducing impact of the projects, and thus there was a mismatch among the various components of the ratemaking formula.[212]

> "[N]one of these revenue increasing or expense reducing impacts that flow from CWIP (and the reliability projects) are reflected in Mr. Ziminsky's revenue requirement determination.... [M]r. Ziminsky's rate base treatment for CWIP

[207] Exh. 11 (Peterson) at 13-14.
[208] It is worth noting that in a brief that extends over 100 pages, Delmarva devotes less than two in discussing CWIP, and notwithstanding the size of the adjustment on rate base (one of Staff's largest adjustments) it was the last issue discussed on the rate base subject and no prior Commission decisions were mentioned. *See*, OB at 76-77.
[209] Exh. 20 (Ziminsky-R) at 62-3.
[210] Exh. 11 (Peterson) at 14; Exh. 13 (Crane) at 9-10.
[211] Exh. 13 (Crane) at 9.
[212] Exh. 15 (Peterson) at 13.

> recognizes only the cost increases that flow from the post-test period construction projects, but does not recognize the service benefits (i.e., increasing revenues and reducing expenses) that flow from CWIP."[213]

The Commission has long held that it has discretion in determining whether to allow CWIP in rate base based on the particular facts and circumstances of each case. In the last two litigated Delmarva proceedings, the Company failed to convince the Commission of the appropriateness of the adjustment.[214] One of the seminal principles upon which the regulation of all utilities is based provides that shareholders are only entitled to a return on and to a return of plant that is both used and useful.[215] CWIP by definition does not meet this requirement and accruing AFUDC on projects until such time as they are completed is the appropriate way to compensate shareholders for the use of their capital.

This approach is unacceptable to Delmarva because the AFUDC rate does not match its authorized rate of return and because it voluntarily does not capitalize AFUDC on all construction projects.[216] This results in an effective earnings rate of only 1.4% ($965,309) on the post-test period CWIP balance of $70,154,772.[217] This imbalance between what the Company voluntarily claims AFUDC on, and the assignment of short term debt to CWIP, is one of the reasons stated by the Commission for its decision to eliminate CWIP from rate base:

> In Delmarva's last electric distribution base rate case, Docket No. 05-304, we exercised our discretion to exclude CWIP from rate base based on the evidence in that case that the amount of AFUDC as a percentage of CWIP was less than 2%. We concluded that including CWIP in rate base under those circumstances would have a "considerable adverse impact" on Delmarva's revenue requirement....
>
> The facts of this case are strikingly similar. The amount of AFUDC as a percentage of CWIP in this case is 0.2%; thus, including it in rate base would

---

[213] *Id.* at 14.
[214] See PSC Orders Nos. 6930 and 8011.
[215] *Chesapeake Utilities Corp.*, 705 A.2d at 1059.
[216] Exh 11 (Peterson) at 14.
[217] *Id.*

have a similar detrimental impact on Delmarva's revenue requirement as we found in Docket No. 05-304.[218]

As noted by the Commission in Docket No. 09-414, the facts once again are very similar and do not support the Company's proposal to include CWIP in rate base. The Company has not raised any new arguments that this Commission did not previously consider in Delmarva's last two litigated cases. Moreover, it violates the principle of intergenerational equity by failing to reflect the revenue-enhancing and/or expense-reducing impact of the projects and, due to the lack of offsetting AFUDC, has an adverse impact on Delmarva's revenue requirement. Staff respectfully submits that the Hearing Examiner and the Commission should once again reject the Company's attempt to corrupt the regulatory triad and exclude the CWIP from rate base.[219]

Nor should Mr. Ziminsky's alternative approach, to create a new regulatory asset for the difference between the Company's accrued carrying charges and the actual AFUDC, be accepted.[220] As witness Peterson pointed out the better approach is to accrue AFUDC on all construction projects, no matter how small, rather than creating a new regulatory asset that would have to be tracked.[221] As the Company admitted there is nothing that precludes it from accruing AFUDC on all construction projects.[222]

C. The Company's Cash Working Capital ("CWC") Requirement Is Overstated, Misleading And Should Be Rejected.

CWC reflects the need for *investor*-supplied funds to meet day-to-day operating expenses that arise from timing differences between when Delmarva spends money to pay those expenses

[218] PSC Order No. 8011, ¶¶ 67-8.
[219] In connection with removing CWIP from rate base, it is appropriate for the Company to capitalize AFUDC and add accumulated AFUDC to plant in service once construction is completed and plant is used and useful. Because the Company's AFUDC adjustment increased its current earnings, Staff witness Peterson made a corresponding adjustment to reverse the Company's AFUDC credit (and reduce current earnings). This adjustment reduces the Company's income under present rates by $965,309. Exh. 11 (Peterson) at 35 and (DEP-1) Sch. 3 at pg. 2b of 7.
[220] Exh. 20 (Ziminsky-R) at 63-4.
[221] Exh. 11 (Peterson) at 15-16.
[222] Tr. at 627.

and when it receives revenues for utility services. The purpose of a lead-lag study for calculating a CWC requirement is to match cash inflows with cash outflows, and thus to determine the level of investor-supplied funds needed for daily operations. Only items for which the Company makes actual out-of-pocket cash expenditures should be included in a lead-lag study.

As a result of its lead–lag study, Mr. Ziminsky included $10,887,807 allowance for CWC in his proposed rate base.[223] Both Staff and the DPA contest the reasonableness of Mr. Ziminsky' lead–lag study since it misrepresents the actual payment terms under which Delmarva receives centralized corporate services from its affiliates.[224] Since nearly 70% of Delmarva's distribution O&M expenses are Service Company charges, the assignment of expense lead days to Service Company billings has a significant impact on the CWC requirements of the Company.[225] Rather than reflecting the actual billing and settlement leads and lags, the Company not unexpectedly chose to inflate the amount of working capital it actually needs, and ratepayer must compensate it for, by assuming that Delmarva paid the Service Company twice a month rather than once a month. This one "slight of hand" with the facts results, as Mr. Peterson explained, in a $4 million dollars increase in the Company's working capital needs.[226] Because the Company actually pays the Service Company once a month around the 15th for services provided the preceding month, the correct expense lead-time to assign to the Service Company is 35.2 days rather than 14.43 days.[227]

[223] Exh. 5 (Ziminsky) Sch. (JCZ)-1, at pg. 1.
[224] Exh. 11 (Peterson) at 17-18; Exh. 13 (Crane) at 13.
[225] Exh (Peterson) at 19.
[226] Witness Crane agreed with the need to reduce the cash working requirements of the Company to reflect the actual payment terms with the Service Company, but calculated the impact differently. *See*, Exh 13 (Crane) at 13.
[227] *Id.* at 18.

The Company's attempt to respond to both Staff and DPA's position on this issue indicates just how weak its argument is. In his rebuttal testimony, Mr. Ziminsky mixes the proverbial "apples and oranges" when he states:

> The 14.43 day lag for Affiliate's Transactions was based on the timing of these types of expenses being recorded on Delmarva's books. The timing of the Service Company's settlement of these transactions is irrelevant to Delmarva's cash working capital requirement. Cash working capital focuses on the cash-basis of accounting in expenses are [sic] recognized when cash is actually expended for products and services. This method differs from the accrual-basis of accounting, which matches expenses when goods and serviced [sic] are provided and not when they are paid. [228]

The Company further compounds its weak argument by suggesting that making this one adjustment to its lead-lag study is arbitrary, while admitting albeit subtly that Staff and the DPA correctly identified the frequency of what it calls an "off-the-book" (meaning cash) transaction.[229] Complaining about how this adjustment will require the entire lead-lag study to be repeated misses the essential point, which is that the transactions between Delmarva and its affiliates represent 70% of all of Delmarva's O&M expense. Rather than having the lead/lag study properly represent the actual cash needs of the Company based on the actual payment date of once a month (the 15th) rather than the fictional two payment dates, the Company protests that it would increase its work load to do it correctly.[230] The Commission should take this opportunity to instruct the Company not to inflate its CWC needs, and thereby its revenue requirements, but to do the lead-lag study correctly so it actually is reflective of the Company's needs. Staff's adjustment reduces the Company's proposed CWC allowance by $3,933,968.[231]

---

[228] Exh. 20 (Ziminsky –R) at 60.
[229] OB at 75-6.
[230] *Id.* at 75.
[231] Exh. 11 (Peterson) (DEP-1) Sch. 2 at pg. 2b of 5.

D. The Company Should Not Be Allowed To Recover Its Regulatory Assets until The Benefits Associated With Those Costs Are Realized by Its Ratepayers

In another attempt to inflate its rate base and make asymmetrical adjustments to its proposed test period, the Company suggests that certain deferred regulatory assets should be recovered now, rather than waiting until the benefits associated with those assets are known and actually received by the ratepayers. The Company readily admits in its direct testimony that the roll-out of these programs was not going to occur until the summer of 2013, some six months after the end of the test period on which rates are suppose to be set in this proceeding.[232] But rather than wait until the investment value is actually known and is used and useful, the Company relentlessly attempts to inflate its rate base by seeking recovery of them now -- $9,550,066 of additional investments -- all of which is outside its selected test period[233] and half of which are not even forecasted to be in service until after the close of this record.

Naturally the Staff and DPA witnesses object to this debasement of the test period in such a perverse way. In the case of the Direct Load Control Program, the Company's filing indicated no deferred costs being incurred during the test period; its entire claim relates to costs being incurred after the test period. As pointed out by Ms. Crane, this program is in its infancy; it is impossible to evaluate it or opine as to its used and usefulness. To grant the Company's request makes a nullity of the Commission's prior order that allows Staff and other parties the freedom to question the level of expense or other aspects of the recovery of the investment in customers' rates.[234]

Staff and the DPA have similar concerns regarding Dynamic Pricing, another program that despite an initial rollout of 6,904 Field Acceptance Test Participants in the summer of 2012,

[232] Exh 5 (Ziminsky) at 17.
[233] *See,* Exh 20 (Ziminsky) Sch. (JCZ-R)-1 at pg. 2 of 6, col. 4.
[234] PSC Order No. 8253, Docket No. 11-330 at ¶ 6.

was essentially rollout with "scale" in the summer of 2013, months after the end of the test period.[235] In both cases, the question is not whether the Company will be able to collect these costs, but when. Delmarva's approach is to try and collect them before any of the alleged benefits can be measured or the reduction in expenses quantified. This was not the intent of the Commission's prior order setting up the Company's right to defer collection of these costs by placing them in a regulatory asset for future recovery.[236] Furthermore, since the Company is on record as stating its corporate policy is to file rate cases on an annual basis, it is appropriate -- as both Mr. Peterson and Ms. Crane suggested -- to await a future case so that any reduction in operating expenses can be identified, quantified and used to offset the additional expense that the Company seeks to recover prematurely in this rate proceeding.

E. The Company's Attempt To Recover Medicare Tax Subsidy In Its Proposed Rates Incurred Prior To The Test Period Should Be Rejected.

The Company seeks to make an adjustment for a change in the Medicare Law, Part D that was enacted in March 2010. The Company has deferred these costs on its books of account. It seeks to recover these costs over three years and to include the unamortized balance in rate base. The Company's proposed increases rate base by $54,650.[237]

Although Staff did not directly address this specific issue in its testimony, it must acknowledge its concerns about retroactive ratemaking and the clear violation of established Commission policy that Delmarva's proposed adjustment entails. As the Company well knows, absent a Commission order allowing a deferral of a cost, a utility is not permitted to recover such costs in future rates. But of course that is exactly what Delmarva seeks to do in making this

[235] Exh. 20 (Ziminsky-R) at 23.
[236] PSC Order No. 7420.
[237] Exh. 13 (Crane) at 26-28.

adjustment, and although the amount is small ($54,650 in rate base additions; $21,860 in earnings reduction),[238] the principle is much larger.

The Company admits that it has no such Commission order in hand that would allow it to defer this cost and collect it in future rates.[239] Nor as Ms. Crane points out did the Company ever seek such an order when the legislation was first enacted and it became known that the Company would be liable for an associated charge.[240] Therefore, there is no basis to include these past costs in prospective rates; to do so would constitute retroactive ratemaking, given the fact that the Company never sought nor received approval for the deferral.[241] Instead, the Company suggests that since it accrued the expense, that expense is now recoverable.[242] That position, however, is not consistent with the law.

A pervasive and fundamental rule underlying the utility rate-making process is that "rates are exclusively prospective in application and that future rates may not be designed to recoup past losses" in the absence of express legislative authority.[243] The rationale of this principle is that the Commission acts in a legislative capacity in exercising its rate-making authority; that rate-making orders have statutory effect; and, that, as such, they are subject to the rules ordinarily applied in statutory construction.[244] Hence, public service commissions and/or courts are precluded, almost without exception, from engaging in retroactive ratemaking unless "the

---

238 Exh. 20 (Ziminsky-R) Sch. (JCZ-R)-1 at pg. 2 of 5.
239 Tr. at 603.
240 Exh. 13 (Crane) at 28.
241 Tr. at 603-4.
242 OB at 72.
243 *Pub. Serv. Comm'n*, 468 A.2d, 1298-1299(citing *Transcon. & W. Air v. Civil Aeronautics Bd.*, 336 U.S. 601, 69 S. Ct. 756, 93 L. Ed. 911 (1949); *Bebchick v. Washington Metro. Area Transit Comm'n*, 485 F.2d 858 (D.C. Cir. 1973); *Louisiana Power & Light Co. v. Louisiana Pub. Serv. Comm'n*, 377 So. 2d 1023 (La. 1979); *Rhode Island Consumers' Council v. Smith*, 111 R.I. 271, 302 A.2d 757 (1973)); see also *Chesapeake Utilities Corp.*, 2011 WL at *10.
244 *Pub. Serv. Comm'n*, 468 A.2d at 1299; *Arizona Grocery Co. v. Atchison, T. & S. F. Ry. Co.*, 284 U.S. 370, 52 S. Ct. 183, 76 L. Ed. 348 (1932).

clearest mandate" exists.[245] In *Chesapeake Utilities Corp. v. Padmore*, C.A. No. K10A-06-008 (RBY) WL 2420681 *10 (Del. Super. June 13, 2011), the court reiterated that the Commission's statutory authority to determine just and reasonable rates is prospective only.[246] The rationale behind this principle is that the Commission acts in a legislative capacity in exercising its rate-making authority; that rate-making orders have statutory effect; and, that, as such, they are subject to the rules ordinarily applied in statutory construction.[247] Moreover, the U.S. Supreme Court has also ruled that to accord a rate order retroactive effect requires "the clearest mandate."[248]

The Commission should reject Delmarva's attempt to violate this seminal principle and accept the DPA's position and eliminate the deferred Medicare Tax Subsidy costs from the Company's proposed rate base.

F. Other Deferrals.

In addition to the three other deferrals that Staff has previously discussed, (i.e., the Medicare Tax Law change, Dynamic Pricing Program, and Direct Load Control Program), the Company also included in its proposed rate base two other deferrals related to (1) the Integrated Resource Planning ("IRP") costs and (2) costs associated with the Request for Proposal ("RFP") for the Blue Water Wind project. Although Staff did not address these two additional deferrals in its direct testimony, Staff supports the DPA's position regarding to the legal prohibition against recovering past costs in current rates without a specific Commission order that allows for the deferral of such costs. Utilities should not be permitted to recover any past costs unless a

[245] *Claridge Apartments Co. v. C.I.R.*, 323 U.S. 141, 65 S. Ct. 172, 89 L. Ed. 139 (1944).
[246] Citing *Pub. Serv. Comm'n*, 468 A.2d at 1299.
[247] *Arizona Grocery Co.*, 284 U.S. 370.
[248] *Claridge Apartments Co.*, 323 U.S. 141; La. *Louisiana Power & Light Co.*, 377 So. 2d at 1028.

specific Commission order permits such deferral. As DPA witness Crane states in her testimony, "Regulation is not intended to be a reimbursement system."[249]

Regarding the IRP, the Company included in its rate base $96,847 of deferred costs. As Mr. Ziminsky states in his testimony, these costs were incurred in August 2009 and were associated with the Company's initial IRP filing.[250] He claims that only costs through July 2009 were included in rates resulting from Docket No. 09-414. Thus, the Company seeks to recover these costs in this proceeding as part of the 2012 test period.

The DPA opposed the recovery of these costs for several reasons. First, there is nothing in the preceding order in Docket No. 09-414 addressing the additional IRP deferrals. Nor was there any authorization for the deferral of these 2009 costs in the order or settlement agreement in the Company's last electric case, Docket No. 11-528. Accordingly, Ms. Crane concludes that there is no specific authority for the continuation of this deferral. More importantly, as witness Crane points out in the Commission's order addressing the Company's initial IRP, the Commission specifically stated that initial IRP costs could be recovered in the subsequent distribution case as a normalized expense.[251] Thus, Delmarva was never authorized to continue deferring the costs associated with its initial IRP. Yet, the Company is proposing a deferral of these costs rather than following the prior Commission's directive that these costs, to the extent they exist, should be normalized.

Finally, as witness Crane points out, the inclusion of $57,474 does not have a material impact on Delmarva's rate base or its earnings. Staff supports the DPA's adjustment since it believes that retroactive ratemaking is not lawful in the State of Delaware.

---

[249] Exh. 13 (Crane) at 19.
[250] Exh. 5 (Ziminsky) at 16.
[251] "In all other subsequent cases such costs shall be normalize as an expense in accordance with Commission practices." PSC Order 7003, Docket No. 06-241 at ¶ 7.

Similarly, the deferral of costs associated with the Blue Water Wind's RFP should also be denied. Here, the Company seeks to include $48,469 in rate base. Similar to its request to recover deferred IRP costs, the Company once again proposes a 10-year amortization and rate base treatment for the unamortized balance.

As witness Crane pointed out, the preceding Commission orders do not authorize the deferral of Blue Water Wind RFP costs. Moreover, the amount of this adjustment is quite small and certainly not material. Asking ratepayers to pay return on these costs over 10 years ignores the fact that some risk of expense recovery should be shared between ratepayers and shareholders. Otherwise, there's no reason to allow the Company a premium over a risk-free rate for its invested capital. Given the fact that these costs do not have a material impact on the Company's financial integrity, it seems rather petty that Delmarva is seeking to recover them now in its proposed rates. Staff supports the DPA's position that they be disallowed.

G. Credit Facility.

The Company proposes an adjustment to recover its costs related to the PHI credit facility. In August 2011, before the beginning of the test-period, PHI renewed the credit facility for a five-year period.[252] Delmarva takes this opportunity to try and recover not only the annual costs of maintaining the credit facility, but also the start-up costs associated with the credit facility (without any Commission deferral order -- amortized over five (5) years). Thus, Mr. Ziminsky proposes a $520,000 adjustment to be included in rate base for the unamortized start-up costs (incurred prior to the test period) associated with the credit facility, as well as an operating expense adjustment of $337,108.[253]

[252] Exh. 5 (Ziminsky) at 30.
[253] Exh. 20 (Ziminsky-R) Sch. (JCZ-R)-1 at pg. 2 of 5.

Staff has two (2) problems with this adjustment. First, as with the Medicare Tax Subsidy issue, an attempt to collect expenses incurred prior to the test period without a specific Commission order allowing such deferral is retroactive ratemaking and cannot be allowed.[254] Second, even though the credit facility is serving the day-to-day cash needs of its companies, such as Delmarva, and recorded as an interest expense for financial reporting, it is not reflected in the cost of capital for ratemaking purposes.[255] Thus, ratepayers are not receiving the benefits of this lower cost of capital since neither commercial paper nor short-term debt, supported by the credit facility, are included in the capital structure upon which rates are being set in this proceeding.[256] If ratepayers are not receiving the benefits of the credit facility, then the costs associated with the credit facility should not be recovered from them.

In addition, as Ms. Crane points out, ratepayers are already paying for the working capital needs of the Company that are being supported by the credit facility.[257] Under the rate making formula, CWC is a component of rate base upon which the Company is being given the opportunity to earn its weighted cost of capital approved by this Commission. The Company is proposing a weighted cost of capital in this case of 7.53%, a rate substantially higher than its short-term debt rate of 0.38%.[258] Thus, the Company is asking the ratepayers to fund both its working capital needs and the costs of the credit facility that is supporting its working capital, without allowing the ratepayers to benefit from the lower financing costs associated with the credit facility. The Company should not be able to have it both ways. Either give ratepayers the benefit of lower financing costs associated with the credit facility or remove the credit facility

---

[254] *Chesapeake Utilities Corp.*, 2011 WL 2420681.
[255] Exh. 13 (Crane) at 29.
[256] Exh. 2 (Boyle) Sch. (FJB)-1 at pg. 1 of 4.
[257] Exh. 13 (Crane) at 30.
[258] *Id.*

costs from the revenue requirement. To do neither as the Company suggests is unfair to its ratepayers.

In this context, Staff proposes to include these costs in the calculation of the AFUDC rate thereby allowing the Company to recover these costs. Since under the uniform System of Accounts, Delmarva first assigns short-term debt to CWIP, which is capitalized to its construction accounts, the Company would be appropriately compensated for its credit facility costs in its AFUDC rate. This method would better match the costs to ratepayers with the benefits resulting from the use of short-term debt, which the Company does not recognize as a source of capital in its proposed capital structure. The Commission should approve Staff's proposal so ratepayers receive some of the value derived from the use of the credit facility to finance short-term needs of the Company. Staff's proposal would remove $520,000 from rate base and reduce operating expenses by $337,108.[259]

H. Rate Base Summary.

The Company's initial Application proposed a rate base of $754,706,877 for its electric distribution operations in Delaware.[260] Staff reviewed the Company's request and made five (5) adjustments that reduced the claimed rate base by $175,962,574 million dollars to $578,744,302.[261] In addition, Staff supports the DPA's additional deferral adjustments.

---

[259] Exh. 11 (Peterson) at 20 and 34; (DEP-1) Sch. 3 at pg. 2b of 7.

[260] The Company proposed a rate base of only $600 million dollars in Docket No. 11-528 based on a test year ending December 31, 2011. One year later the Company's rate base has expanded by 26% to $754 million dollars based on the Company's initial filing in this docket.

[261] Exh. 11 (Peterson) at 22-3.

VIII. <u>OPERATING EXPENSES</u>

A. Introduction.

While the utility's legitimate expenses incurred in the course of providing safe, adequate and reliable service are to be allowed in the absence of waste, bad faith or an abuse of discretion, the mere fact that a utility has incurred an expense does *not* mean that ratepayers are automatically required to pay that expense through their rates. The United States Supreme Court has held that in determining whether a particular expense is reasonable and should be charged to ratepayers, a commission must consider the effect of the expense on both the ratepayers and the shareholders. In *Fed. Power Comm'n v. Memphis Light, Gas & Water Div.*, 411 U.S. 458, 474, 93 S. Ct. 1723, 36 L. Ed. 2d 426 (1973) *disapproved on different grounds by United States v. Woods*, 134 S. Ct. 557 (U.S. 2013), the Supreme Court stated that "rates are 'just and reasonable' only if consumer interest<u>s</u> are protected and if the financial health of the [utility] in our economic system remains strong." Staff submits that in examining the various parties' objections to particular expenses that Delmarva seeks to include in rates, the Commission should be mindful of whether some or all of those expenses are truly necessary for the provision of safe, adequate and reliable utility service or whether safe, adequate and reliable service could be provided in the absence of those expenses.

B. Wage Increases Beyond the Test Period should be Rejected.

In an effort to increase its test period expenses, and in conjunction with its stated corporate policy to file rate cases annually, Delmarva takes the opportunity in its Application for new rates to stretch out its wage increase request through October 2014, almost two full years passed the end of the test period, December 31, 2012.

The Company is quick to suggest that in accordance with prior Commission decisions, these wage increases should be approved, even though the Board of Directors has not even approved some of increases yet. Therefore, they cannot be either known or measurable.[262] Staff and the DPA properly pointed out that the Company had not reached any labor agreement with its union for 2013 at the time both parties filed testimony, much less any 2014 increase for the non-union contract, approval of which is purely discretionary with the Board.[263] As Mr. Ziminsky indicated in his rebuttal testimony there are years when the Board has decided no increase in the level of wages paid to non-union employees is appropriate.[264] But the changed circumstance that Delmarva fails to address is that the rate effective period in this case is unlikely, given its parent's stated policy of filing rate cases every year, to last beyond 2013. Consistent with its stated objective, Delmarva has filed 2 rate cases -- Docket No. 11-528, using a test period of 12 months ending December 31, 2011, and this case, using a test period of the 12 months ending December 31, 2012. It is likely that a rate filing will occur on the heels of the resolution of this matter, which in all probability would use a test period of 2013. Any wage increases that fall outside the test period in this case would be picked up in the next case. Thus, this is the new normal and the Commission must adjust its thinking and decision making to reflect what the Company has stated is its new policy with regard to annual rate filings. Accepting only the known and measurable changes that occur in the test period in this matter is appropriate and preserves the relationship between expenses, revenue and capital investment. The Company is not harmed since it will recover any adjustments to wages not reflected in the

[262] Tr. at 586-7.
[263] Tr. at 586.
[264] Exh. 20 (Ziminsky-R) at 25.

test period in its next filing. Thus, Staff's adjustment should be accepted and payroll expenses reduced by $513,480.[265]

C. Staff's Adjustment to Remove all Non-Executive Incentive Compensation Should Be Accepted.

Notwithstanding the Commission's most recent decisions on this issue, the Company once again includes costs related to non-officer incentive compensation as part of its revenue claim. This time it inflates Delmarva's revenue demand by $1,993,802 for incentive payments made during the test period under the 2012 Annual Incentive Plan ("AIP") applicable to Delmarva and PHI Service Company non-executives. As in the past, the current version of the AIP requires certain financial earnings goals to be met before any compensation under the plan is paid out. Thus, as Mr. Peterson pointed out, the plan creates a financial threshold on the Company's ability to make performance related payouts irrespective of whether other financial, safety or other goals are met.[266] For utility employees, utility earnings have to reach a 90% threshold to qualify for any benefits under the plan. Likewise, Corporate Service employees are eligible only if certain utility or non-regulated earning targets are met or exceeded. Consequently, even if other individual or team goals are met or exceeded, no incentive payments would be paid unless the financial threshold targets are also met.[267]

The plan is also asymmetric in that the award percentages increase as pay scales rise. Thus highly compensated employees are eligible for a proportionately greater incentive award than less highly compensated ones. For example, pay grades 1- 4 are eligible for only five (5)

[265] Exh. 11 (Peterson) at 24.
[266] *Id.* at 25.
[267] *Id.* at 26.

% of base pay in incentive awards, while employees in grades 15 and up receive awards of up to 15% of base pay.[268]

In Docket Nos. 05-304 and 09-414, the Commission excluded from the Company's cost of service the amount of non-executive incentive compensation expense attributable to achievement of financial goals, concluding that since shareholders primarily benefit from the achievement of those goals, shareholders should pay for them.[269] The tautology of the Commission's logic in rejecting this adjustment is apparent when one considers that the plan requires the ratepayers to pay higher compensation costs (i.e., rates) as a consequence of higher corporate earnings. This upward spiral in rates does not directly benefit ratepayers, but does benefit shareholders by making it more likely that the high payout ratio used to sustain the Company's dividend can be maintained.

In addition, it insures the further enrichment of senior personnel as the Company's earnings reach or exceed the targets that are pre-determined by management. As Ms. Crane pointed out, the proper rate of return to reward shareholders within a regulated environment is the responsibility of the Commission. Allowing a utility to charge ratepayers an additional return that is then distributed to employees as a part of a plan to divide extraordinary profits is unfair to ratepayers and unwarranted. Nevertheless, the Company included almost $2 million dollars of such expenses in this case, arguing that the incentives are part of non-executive employees' total compensation package and that they benefit customers by extending the period between rate cases.[270] The Company contended that the program: (1) allows Delmarva to attract and retain skilled employees; and (2) creates incentives to attain levels of

[268] *See*, Exh 29.
[269] PSC Order No. 6930, ¶¶ 96-98 (June 6, 2006); PSC Order 8011 at ¶ 194-6 (August 9, 2011).
[270] Of course, this reasoning (lengthening the time between rate cases) is not applicable here since the Company's stated corporate policy –now-- is to file cases annually. Tr. at 257*; See generally*, Exh. 34 at 8.

performance that benefits customers.[271]

Staff removed all non-executive compensation expenses based, in part, on the decisions reached by the Commission in Docket Nos. 05-304 and 09-414. Similar to the plans at issue in the two prior litigated cases, the 2012 AIP provides that payouts will be made *only* upon attaining overall corporate earnings threshold of 90%. As Mr. Peterson stated, if Delmarva were more interested in providing incentives for achieving employee and public safety or ratepayers' satisfaction goals, there would be no financial screen through which any compensation under the plan must pass.[272] The earnings threshold as a necessary pre-condition demonstrates that the paramount goal of the AIP is to increase shareholder dividend income, which is inconsistent with the ratepayers' implicit goal of receiving service at the lowest reasonable price.[273]

In addition, if the Company files rate cases on a more routine basis (with one coming perhaps as soon as 2014), the question becomes how do the programs lengthen the time between rate cases or mitigate the rate impact of such rate cases? Indeed, the Company must admit that ratepayers would not benefit from the incentive programs under those circumstances. Furthermore, the Company must also admit that it is possible that no incentive compensation payments would be made in 2013 if the financial threshold is not met. In that case, including an allowance for such payments in the Company's revenue requirement would result in ratepayers paying an expense that the Company is not incurring. Thus, there is a good reason for excluding incentive compensation payments that are so closely linked to corporate earnings. If earnings fall below the objectives set forth in the plans, stockholders are protected because no incentive payments are made even though all of the other performance criteria were met or exceeded. But

---

[271] Exh. 17 (Boyle-R) at 10.
[272] Exh. 11 (Peterson) at 26.
[273] *Id.*

by building incentive compensation into rates, ratepayers have to pay the expenses regardless of whether the corporate earnings target is achieved and whether the incentives are actually paid to employees. Clearly, the stockholders benefit when corporate financial objectives are met. If the Company wants to offer its employees an incentive program triggered by financial goals, it is free to do so -- but the stockholders who benefit from the achievement of those financial goals should pay for it, not the ratepayers.

Finally, as Mr. Boyle candidly admitted -- ratepayers should expect Delmarva employees to provide quality performance even without an incentive program; that its employees would not reduce the quality of their performance if their incentive compensation were reduced; and that Delmarva would be able to meet its statutory obligation to provide safe, adequate and reliable service without ratepayer-funded incentive payments.[274]

The current trend among regulatory authorities is to allow only those expenses truly necessary for the provision of safe, adequate and reliable service. See, e.g., *Narragansett Elec. Co. v. Rhode Island Pub. Utilities Comm'n*, 35 A.3d 925, 937 (R.I. 2012)(company failed to demonstrate that the $2.4 million cost associated with the incentive compensation plan would provide significant direct benefits to ratepayers); *Illinois Commerce Comm'n v. Com. Edison Co.*, 10-0537, 2012 WL 5374117, , *22 (Ill. C.C. Oct. 17, 2012)(Commission requires evidence that Annual Incentive Program, i.e., incentive compensation costs, benefits ratepayers before costs may be recovered; Commission rejected recovery for AIP costs because such costs did not relate to energy efficiency activities and programs); *Commonwealth Edison Co. v. Illinois Commerce Comm'n*, 398 Ill. App. 3d 510, 924 N.E.2d 1065, 1078 (2009)(upheld commission's determination that disallowed incentive compensation expenses provided only tangential benefit to taxpayers despite utility's argument that incentive compensation plans

[274] Tr. at 281.

benefit consumers by increasing productivity and customer service and attracting better employees).

Staff is not saying that the Company cannot pay incentive compensation to non-executive employees. If it does, however, the ones who benefit from the achievement of the financial goals -- the shareholders -- should pay for those benefits. Unlike customers of competitive companies who can take their business elsewhere if the cost of a product or service is too high, Delmarva's ratepayers have no choice but to continue to pay for it.

The Commission considered each of the Company's arguments here in Docket Nos. 05-304 and 09-414, and ultimately found them wanting in light of the fact that the plans at issue there were primarily driven by financial goals. Here, the AIP is purely driven by financial goals since achievement of earnings thresholds is the only way any payment gets made regardless of whether the safety/customer service/reliability goals are met. Staff's removal of non-executive incentive compensation payments should, therefore, be accepted. The revenue requirement effect is to increase net operating income by $1,993, 802. [275]

D. Staff's Proposed Adjustment to Healthcare Benefits Should Be Accepted.

The Company increased test period expense by 8% for medical expenses and 5% for vision and dental expenses, based on "work" by the Company's benefits consultant, Lake Consulting, Inc. ("Lake").[276] Staff rejected this additional attempt to increase test period expenses because: (1) Delmarva is self insured; and (2) the adjustment is based on general trends in healthcare costs and not on Delmarva's actual results.[277] The Lake study has no data that is specific to Delmarva. Instead, the study is based on trends in medical premiums experienced by several major insurance companies. In order for the Commission to accept this

[275] Ex. 11 (Peterson) Sch. 3 at pg. 2a of 7, col. E.
[276] Ex. 5 (Ziminsky) at 15.
[277] Ex. 11 (Peterson) at 27-28.

increase in test period operating results it must find: (1) that the general trends are similar to Delmarva's actual experience, of which there is no evidence; and (2) that use of a post-test period trends, not related specifically to Delmarva, is a known and measurable change.

Although Lake showed an average increase of 6.1% in dental expenses, the Company only increased the test period expense level by 5%. Similarly, although the estimated average medical expense increase was expected to be 9.5%, the Company only increased the test period expense level by 8%.[278]

As shown above the Company's values used to inflate test period operating results are just estimates that they used based solely on the opinion of Delmarva employees.

Third, there is no evidence that any of the companies that Lake surveyed provide coverage to Delaware employees, or that the expense trend in the geographic area it surveyed is representative of the expense trend in Delaware. Indeed, Staff suggests that it is not: the Virginia-Maryland-District of Columbia area is well known to be more expensive than Delaware and Delmarva's own experience demonstrates that. Rather than basing its future medical projections on actual results in Delaware, the Company chose to use general trends.[279]

This adjustment is not "reasonably known and measurable;" it is based on estimates derived from a survey of companies in a different geographical area. It should be rejected. The revenue impact is to increase net operating income by $318,199.[280]

E. Staff's Adjustment to the Proposed Regulatory Commission Expense is Appropriate and Should be Accepted.

The parties agree that the recovery of regulatory commission expenses should be normalized and recovered over a three-year period. But Staff and the DPA take exception to including

[278] Exh. 5 (Ziminsky) at 31.
[279] *See*, Exh. 20 (Ziminsky-R) at 31.
[280] Exh. 11 (Peterson) (DEP-1) Sch. 3 pg. 2a of 7.

estimated costs for this proceeding, and including them in the calculation when such costs are not known or measurable. Unlike the allowance that Mr. Ziminsky is recommending for non-rate case regulatory commission expense, which is based on a three year average of actual expense ($53,316), he instead estimates the cost of this rate proceeding ($632,000) and suggests that it should be included in the amount normalized over three years. Given the wide variation in rate case expenses in the last several Delmarva electric filings, it seems odd that the Company would use the highest value and extrapolate that as the estimate for this case, especially given that the last preceding was settled.

As Mr. Peterson illustrated in his testimony, the rate case expense over the last several cases has varied significantly: [281]

Delmarva Electric Rate Case Expense

Docket No. 11-528 (settled)	$634,054
Docket No. 09-414 (litigated)	$245,241
Docket No. 05-304 (litigated)	$400,000
Average	$426,432

Since we do not know what the actual rate case expense will be in this proceeding, and Mr. Ziminsky is merely guessing at what the expected cost may be, Staff and the DPA witness used an average of the last three years to determine the value to be normalized as the rate case expense. For Staff this resulted in a $68,723 reduction in the requested rate case expense allowance.

Mr. Ziminsky also proposed to include in rate base the unamortized balance of regulatory commission expense, suggesting that the costs incurred by the Company "are required and necessary costs that the Company has and will actually incur…" [282] This "novel" idea, Staff believes is being proposed for the first time in Delaware, disaggregates any benefit received by the

[281] *Id.* at 29
[282] Exh. 20 (Ziminsky-R) at 19.

Company in having its rates increase, its earnings improve and its dividend more likely to be protected, from the cost of achieving those benefits. While acknowledging that the timing of the filing of cases is within the exclusive control of the Company, and that stockholders benefit from having their dividends paid, in the Company's view of the regulatory world the ratepayers should pay 100% for those benefits.[283] No balance needed here, just let's asks the ratepayers to pay. Given the Company's prospective throughout this proceeding, this one sided, inequitable attempt to stick ratepayers with the Company's unilateral decision to file rate cases, now every year, should not come as a surprise, but should be rejected. Staff's proposed adjustment to reduce rate case expense should be accepted.

F. The Integrated Resource Plan ("IRP") Recurring Costs Need to be Reduced.

Again, the Company has tried to increase the level of expense associated with its IRP Filing by estimating an unknown cost rather than relying on historical information to make a more reasonable adjustment. As Mr. Peterson pointed out, the Company has been filing IRPs since 2006. As he points out, although costs have varied over the years, the Company has seven (7) years of history of annual IRP-related costs. But rather than relying on these known figures, and normalizing them, the Company once again tries to suggest the expense level for these costs should be set at an amount that has not been experienced in the last several years.

Year	Actual IRP Cost[284]	Expense Level Collected In Rates[285]
2009	$367,373	$1,875,000
2010	$927,875	$1,875,000
2011	$ 46,909	$1,875,000

283 *Id.*
284 Exh. 11 (Peterson) (DEP-1) Sch.3 pg. 6 of 7.
285 Exh. 20 (Ziminsky) at 34.

2012	$302,062	$1,255,340

Not satisfied that since 2009 the Company has over collected these costs by hundreds of thousands of dollars, and knowing that the current schedule for IRP Docket No. 12-544 has no evidentiary hearings scheduled, Delmarva is still not satisfied to use an average of historical costs ($700,000) rather than its estimates. As Mr. Ziminsky indicated in his rebuttal testimony, and on the stand, the actual costs reflected in Mr. Peterson's schedule are substantially less than what is currently in rates.[286] As shown, the difference between the actual costs and the expense level included in rates is increasing. Thus reducing the amount collected in rates to more properly reflect actual cost incurrence is not only appropriate, but fairness demands it. Staff adjustment should be accepted.[287]

G. DPA's Adjustment to Remove SERP Benefit Expenses Should Be Accepted.

Although Staff did not address this issue in this proceeding, it supports the DPA's adjustment to remove this expense from the Company's test period operating results.[288] The SERP (Supplemental Employee Retirement Benefits) provides retirement benefits to Company executives over and above the many benefits that they already receive under PHI's other retirement plans.[289] DPA removed the SERP benefits from the Company's cost of service on the ground that ratepayers should not be burdened with funding these additional benefits, especially in light of the compensation that senior executives are already receiving, ranging

[286] *See*, Exh. 20 (Ziminsky) at 34; Tr. at 593.
[287] Again the Company suggests as an alternative to normalizing the average IRP costs, creating a deferred asset for the difference so eliminate any risk of under collection. For the reasons cited with regard to rate case expense, Staff is opposed to this proposal.
[288] Staff did address this issue in the last Delmarva litigated case Docket No. 09-414 and made an adjustment to remove it.
[289] Ex. 13 (Crane) at 39.

from $ 1.5 million dollars for the new General Counsel to $11.3 million dollars for Mr. Rigby PHI's CEO.[290]

In rebuttal, the Company contends that offering these benefits is a way to circumvent the IRS salary caps found in qualified defined benefit pension plans. Stated another way, if Mr. Rigby's salary, or Mr. Boyle's who testified on behalf of the incentive plans, were to be included in the calculation, the required benefits to the typical employee would dramatically increase. Instead, the SERP allows the Company to discriminate in favor of the highly compensated, which the Company suggests is because "[e]xecutives do not receive equitable pension contributions, relatively speaking, when compared to the typical company employee."[291]

This argument is no more persuasive in this context than it is in the context of incentive compensation benefits. Staff has not challenged the inclusion of many of the executive retirement benefits in the Company's cost of service. But this is *additional* executive compensation *over and above* what these executives will receive as part of those retirement benefits. It is called supplemental because the benefits exceed various limits imposed on retirement programs by the IRS and therefore are captioned "Non-qualified" since the payout ratios are much higher than exist under normal "qualified" pension plans.

Rate recovery for SERP expenses should only be permitted if it has been established that the payment of the expense provides benefits to ratepayers. While executive incentive plan expenses are not at issue in this case, SERP expenses are and Delmarva provided no evidence whatsoever that establishes any benefit, direct or indirect, to ratepayers related to this program. Arguments that such benefits are necessary to attract and keep highly skilled and

---

[290] *Id.* at 40.
[291] *See*, Exh 20 (Ziminsky-R) at 75.

talented executives, who are all making hundreds of thousands of dollars -- if not millions of dollars in compensation -- should fail of their own weight. In an era in which ratepayers are being confronted with repeated requests for rate increases, elite benefits for the select few should not be included in the cost of service and paid for by ratepayers unless and until there is some benefit that can be measured or quantified from which the ratepayers profit. Removing this executive benefit will increase net operating income by $653,963.[292]

H. Dynamic Pricing Program.

The Company proposes a series of adjustments to reflect its desire to collect certain costs associated with the Dynamic Pricing Program. Its adjustments include: (1) beginning a 15-year amortization of previously deferred costs associated with the program; (2) include in the Company's revenue requirements O&M costs related to the program that are not already included in rates; and (3) include in the Company's revenue requirement an amortization expense for related equipment costs.[293]

As Staff witness Peterson indicated, because the full deployment of the Company's Dynamic Pricing Program did not occur before or during the test period, the related benefits and savings to be achieved through that program will not be reflected in the Company's test period results. Moreover full deployment of the program will not be completed until well after the test period is closed. Again, the difference between recognition of the program's related costs, and receipt of the expected benefits to be achieved through the program, creates a mismatch of test period results that should be avoided. Accordingly, Staff is recommending that the Company continue to defer all incremental costs associated with the Dynamic Pricing Program until the

---

[292] Ex. 13 (Crane) Sch. ACC-21.
[293] Exh. 11 (Peterson) at 31.

next base rate proceeding following the full deployment of the program. Since these costs are being deferred, the Company is protected and will eventually recover these costs -- assuming that they are necessary and reasonably incurred.[294]

I. Direct Load Control Program.

Similar to Delmarva's Dynamic Pricing Program, implementation of the Direct Load Control program is too far beyond the end of the test period to be recovered now. Since this program started in the summer of 2013, after the test period, and is expected to continue through 2016, the benefits expected to accrue from the program are not factored into the test period operating results. Since these expenses are being deferred, the Company is protected and assured of future recovery of these costs if they are deemed necessary and reasonably incurred. Staff's adjustment should be accepted.

J. AFUDC.

Staff's adjustment recognizes that in removing CWIP from the Company's rate base, the associated credit to income (the carrying costs associated with those construction projects) must be removed from its operating income. Thus, if Staff's recommendation regarding CWIP is accepted, test period operating income should be reduced $965,309.[295]

K. Automatic Metering Infrastructure ("AMI").

The Company states in its testimony that AMI has been fully deployed to all Delaware customers.[296] Accordingly, it proposes a series of adjustments to reflect in rates ongoing O&M expenses, associated savings, depreciation and amortization expenses. However, as Mr. Peterson pointing out, there may be additional savings associated with remote turn on and turn off that are not quantifiable at the present time. Because the ability to achieve these savings is dependent

[294] *Id.* at 32.
[295] *Id.* at 35.
[296] Exh. 5 (Ziminsky) at 17.

upon Delmarva receiving a favorable ruling from the Commission on its request to amend the Commission's termination rules, these potential savings are unknown. Mr. Peterson recommends that if a favorable ruling from the Commission is received, that Delmarva should defer the associated savings as a credit to the Company's AMI regulatory asset account, which is already set up by prior Commission order, until the Company's next base rate proceeding when the savings can be factored into base rates.[297]

L. Wilmington Franchise Tax.

The Company includes a 0.106% allowance for the Wilmington Franchise Tax in its revenue conversion factor. The Company proposes to collect the tax from all of its Delaware distribution customers, as it has in the past, including customers living outside the city limits of Wilmington.

Staff witness Peterson disagreed with including this tax in the conversion factor, which means: (1) it is over collecting since all customers pay the tax, not just the residents of Wilmington; and (2) customers outside the City are paying for municipal services they are not actually receiving. Believing that only customers who are located inside the city limits should actually pay this tax, since they actually receive the city services for which this tax is levied, Mr. Peterson removed the franchise tax from the revenue conversion factor and suggested that Delmarva's distribution tariff, and the Company's monthly customer statements, be modified to include an assessment of the Franchise Tax to only customers located within Wilmington.[298] Although the Company did not take a position on this issue, it did agree if ordered by the Commission it would make the adjustment.[299] The Commission should order the Company to do so.

---

[297] Exh. 11 (Peterson) at 30.
[298] Exh. 11 (Peterson) at 35.
[299] Tr. at 618-19.

M. Interest Synchronization.

Because Staff recommended a lower rate base than that being proposed by Delmarva, the interest expense associated with Staff's rate base must be adjusted as well and synchronize with the debt portion of the overall return that Staff is recommending. The pro forma tax deduction for interest expense is the product of the weighted cost of debt (2.49%) and Staff's rate base determination ($578,744,302). This results in a $1,781,279 increase in income taxes and therefore reduces net income accordingly.[300]

IX. COST OF SERVICE/RATE DESIGN/REVENUE DISTRIBUTION.

A. Delmarva's class cost of service study ("COSS") should not be used to distribute its revenue requirement among the customer classes for rate design purposes because such COSS is flawed in several respects, but primarily in its disregard of cost-causation principles.

Cost causation is the central principle of all cost allocation.[301] This principle means that costs should be allocated on the basis of factors that cause the cost to be incurred.[302] Hence, a COSS should reflect as accurately as possible the direct assignment and allocation of costs to the customer classes based on the cost-causative impact of each class on the distribution system.[303] Delmarva's COSS fails to comport with this principle in three primary ways: It only apparently functionally separates underground and overhead facilities; its demand allocators do not reflect diversity at the load center level; and it employs four composite allocators that use an arbitrary 50/50 weighting of other allocators.

Mr. Tanos testified for Delmarva and explained how he designed the Company's COSS. He stated that functionalized costs are classified as demand-related or customer-related based on

[300] *Id.* at 34.
[301] Electric Utility Cost Allocation Manual, National Association of Regulatory Utility Commissioners, January 1992 ("NARUC Manual"), at 12-13.
[302] *Id.* at 21 and 75-77.
[303] Exh. 10 (Pavlovic) at 12; Exh. 8 (Tanos) at 8.

cost causation.[304] He also stated that demand-related costs are fixed costs that are dependent on kW requirements and represent the instantaneous demand imposed on the system. He further stated that customer-related costs are fixed costs associated with the number of customers served. As for cost allocation, Mr. Tanos stated that functionalized and classified costs are apportioned to the particular customer groups, and distribution costs that serve only a particular customer class are directly assigned to that class. The remaining costs are allocated to the customer groups based on a method that is considered most consistent with cost causation.

Mr. Tanos also testified about the cost of service model that Delmarva used to directly assign or allocate each element of Rate Base, Revenues, and Operating Expenses to the respective customer classes.[305] The cost model includes allocation factors used to assign the specific components of Total Distribution cost to the customer classes. After allocating the Total Distribution costs, the costs are aggregated by customer class to determine the cost to serve each class and to compute the class rate of return for that class. Based on the testimony of Tanos, Delmarva's COSS contains certain fatal flaws.

1. **First, the COSS does not include separate allocators for underground and overhead facilities. Because underground distribution facilities cost more than overhead facilities, the costs of such facilities are not being accurately allocated to the customer classes.**

In general, residential customers use overhead distribution facilities more than commercial customers.[306] Although Delmarva properly functionalized its underground and overhead facilities separately,[307] it then used the same demand allocator for both the underground and overhead facilities which, in effect, undid the separate functionalization.[308] Underground

[304] Exh. 8 (Tanos) at 5.
[305] *Id.* at 6.
[306] Exh. 10 (Pavlovic) at 12-13.
[307] NARUC Manual, at 89.
[308] Exh. 10 (Pavlovic) at 12.

and overhead facilities, however, have significantly different cost characteristics and typically are used in different proportions by residential and commercial customers.[309] In fact, Mr. Tanos acknowledged that underground distribution facilities cost more in general than overhead distribution facilities.[310] Because commercial customers generally make greater use of underground facilities, and because underground facilities are generally more expensive, Delmarva's use of a single allocator that does not reflect the differences in customer classes' use of overhead and underground facilities represents a source of inaccuracy in the COSS and likely results in over-allocation to underground costs to the residential class.[311]

Delmarva attempted to use speculative evidence to support using a single allocator for overhead and underground facilities. Mr. Tanos stated that 95% (or 4,395) of new residential customers in planned subdivisions in Delaware requested underground service versus 71% of new commercial customers.[312] These numbers and percentages, however, fail to provide support for the use of a single allocator for underground and overhead facilities. In fact, on cross examination Mr. Tanos admitted he had no data on exactly how many of the requesting residential customers actually received such installed underground services.[313] Therefore, Delmarva's failure to use separate allocators for underground and overhead facilities in its COSS leads to a violation of the cost-causative principles.

2. **Second, Delmarva uses demand cost allocators in the COSS that do not accurately reflect class cost responsibility for the demand-related facilities in <u>its distribution system.</u>**

309 *Id.*
310 Tr. at 926-927.
311 Exh. 10 (Pavlovic) at 13.
312 Exh. 8 (Tanos) at 6.
313 Tr. at 936.

To develop proper allocators for electric utilities, accurate and usable load data must exist.[314] This data includes hourly load information per customer class based on load research studies (diversity factors), line loss studies, number of customers served in each customer class at each voltage level, monthly usage (kWh) and demand (kW) information for each customer class, and customer related cost data (meter and billing costs). For electric companies, this data is obtained from load research performed before the actual allocation of costs.[315] The information about system and class loads is necessary in the COSS because this data allows for the development of the appropriate allocators.[316]

Delmarva uses three demand allocators in its COSS: (1) DEMPRI,[317] (2) DEMSEC,[318] and (3) DEMTRNSF.[319] With regard to the latter two allocators, Delmarva has improperly measured class diversity by using a demand measure that assumes zero diversity. The DEMSEC demand allocator is based on a 50/50 weighted split between the Class MDD[320] and the Customer NCP[321] demand measures. Delmarva has specifically defined the Customer NCP demand measure as a *non-diversified* demand measure.[322] Similarly, the DEMTRNSF demand

[314] NARUC Manual at 90, 97-98, and 100-101.
[315] NARUC Manual at 97-98.
[316] *Id.*
[317] DEMPRI is defined by Delmarva as "Distribution Primary system-related allocator based on Class Maximum Diversified Demand (Class MDD)." See Exh. 8 (Tanos), Sch. (EPT)-4, at 1.
[318] DEMSEC is defined by Delmarva as "Distribution Secondary-related allocator on a unitized weighted 50/50 split of Class MDD and a sum of the customer maximum non-coincident demands (Customer NCP). Excluding General Service Secondary Large and General Service Primary." *Id.*
[319] Exh. 22 (Tanos) at 2. DEMTRNSF is defined by Delmarva as "Distribution Secondary-related allocator for Line Transformers based on a unitized weighted 50/50 split of Class MDD and Customer NCP. General Service Secondary Large allocation was based on Customer NCP only. Allocation excluded General Service Primary." Exh. 8 (Tanos), Sch. (EPT)-4 at 1.
[320] Delmarva defines Class MDD as "the maximum hourly demand found for the customer class over the analysis period where the simultaneous demands of the class of customers is taken as a whole." See attachment to Exh. 10 (Pavlovic), PSC-COS-30, at ¶1.
[321] Delmarva defines Customer NCP as "the sum of the individual maximum demands of the customers within a class on a customer-by-customer basis over the analysis period." See attachment to Exh. 10 (Pavlovic), PSC-COS-29, at ¶1.
[322] See attachment to Pavlovic, PSC-COS-30, ¶1: "The diversified (Class MDD) and ***the non-diversified (Customer NCP) demand allocators*** that are used in the cost of service study consider this when assigning investment." (emphasis added).

allocator is based on an averaging of the Class MDD and Customer NCP demand measures.[323] Again, half of the allocator is based on a non-diversified demand measure that reflects zero diversity. As pointed out by Staff's expert, Dr. Pavlovic, it is extremely unlikely that the actual diversity on Delmarva's facilities is zero.[324] Because two of Delmarva's demand allocators are inaccurately measuring the diversity on the Company's facilities, there will be an under-allocation of the facility costs to some of Delmarva's customer classes and an over-allocation of such costs to the others.[325]

Delmarva admitted that it has failed to do any class studies to measure its actual class diversity on its distribution system or, as explained below, to determine what the proper mix of demand measures is.[326] Thus, there is no way to determine if the residential customers (or any other class of Delmarva customers) are paying too much or too little for the distribution facilities. The demand data from the AMI[327] would clarify this, and Delmarva admits this fact.[328] Moreover, such AMI data would be an extremely accurate basis for developing demand allocators for Delmarva's distribution system.[329] But Delmarva also claims that it is too soon to use the AMI data and that after one year's worth of AMI data (starting from August 29, 2013), only then could it accurately determine its class allocators.[330] Rather than agree to use the more accurate AMI data, Delmarva alleges that its arbitrarily determined 50/50 weighted allocation method is "reasonable" and should be used here. However, the 50/50 weighted allocation is

[323] Exh. 8 (Tanos), Sch. (EPT)-4 at pg. 1.
[324] Exh. 10 (Pavlovic) at 13-20.
[325] Exh. 10 (Pavlovic) at 14.
[326] Tr. at 945-946; 949.
[327] AMI stands for Advanced Metering Infrastructure. AMI encompasses a whole electricity information network including Smart Meters on customer houses, communications to and from a utility.
[328] Tr. at 938-939.
[329] Exh. 10 (Pavlovic) at 15-16.
[330] Exh. 22 (Tanos-R) at 6.

unsupported by currently-existing data and hence arbitrary.[331] Because Delmarva has failed to use actual load data to determine the class diversity on its facilities, the cost responsibility for its expenses will fail to be accurately reflected in the COSS. In this additional sense, Delmarva's demand allocators in the COSS contain a fatal flaw and do not align with the primary principles of cost-causation.

Delmarva also failed to use recent load data in developing proper demand allocators. As a principle, load data used for demand allocators should come from the same time period as used in the COSS. If the data is out-of-period, the utility must show that the data is representative of the actual loads in the test period. Delmarva admitted that the load data used for the COSS is not contemporary. In fact, Delmarva used data from the year ending 2011[332] and failed to update its COSS to include demand data even though it could have[333]—and should have -- updated such 2011 study with 2012 load data. This additional inaccurate demand allocation formulation should be rejected by the Hearing Examiner and the Commission.

3. **Third, Delmarva's COSS uses an arbitrary 50/50 weighting or averaging of <u>demand allocators</u>.**

After functionalizing costs into cost classifications and then classifying costs by aligning them by the service characteristics that gave rise to the costs, the third step in COSS is to allocate costs to the various customer groups based on the costs caused by that group (i.e., based on each group's responsibility for the service provided by the utility). For Delmarva's distribution costs, the two primary cost drivers for the allocation step are the number of customers served by the distribution system and the customer demand (kilowatts) on the distribution system.[334]

[331] Tanos testified on cross examination that the demand allocators were based on his experience in the industry. Tr. 945 to 946; 949.
[332] Tr. at 900.
[333] Tr. at. 901.
[334] Exh. 10 (Pavlovic) at 6.

Delmarva takes a standard approach of functionalizing its distribution costs based on FERC accounts, then classifying the functionalized costs as either demand-related or customer-related, and finally allocating to its customer classes the classified costs using various demand-related and customer-related allocation factors.[335]

Staff's witness Pavlovic pointed out that some of Delmarva's transformers serve single customers and others serve multiple customers; however, Delmarva arbitrarily uses a simple average, 50/50 split, of its Customer NCP demand measure and Class MDD demand measure to allocate transformer cost responsibility.[336] As noted by Mr. Pavlovic, it is extremely unlikely that exactly 50% of Delmarva's transformers serve single customers and 50% serve multiple customers.[337] Hence, it is extremely unlikely that an arbitrary 50/50 weighting of the two demand measures will accurately reflect the actual class cost responsibility for transformers.[338] If a utility's costs of providing service are not accurately allocated to its rate class and rate class costs are not accurately reflected in the rate classes' tariff billing charges, then the utility will either over- or under-recover its costs of service or revenue requirement.[339] Without accurate cost measures that do not produce a preference for discrimination against specific customer classes, Delmarva's COSS fails the requirement in 26 *Del. C.* § 303(a) that no public utility may make, impose, or extract "any unjust or unreasonable or unduly preferential or unjustly discriminatory individual or joint rate for any product or service supplied or rendered by it within the State...."

By using a composite of allocators with arbitrary weighting of cost metrics, Delmarva further compounds the use of demand measures that assume zero-diversity. Delmarva uses two

[335] Exh. 10 (Pavlovic) at 11; Exh. 8 (Tanos) at 4, 5, and 6.
[336] Exh. 10 (Pavlovic) at 15 (citing PSC-COS-30 and PSC-EPT-10 and 11).
[337] *Id.*
[338] *Id.*
[339] Exh. 10 (Pavlovic) at 6.

demand-related allocators and two customer-related allocators are composite, i.e., they are calculated as the simple average or 50/50 weighting of two cost metrics.[340] The demand allocators DEMSEC and DEMTRNSF are 50/50 weightings of the demand cost metrics Class MDD and Customer NCP.[341] The customer allocators CSERV and CSALES are 50/50 weightings of the customer cost measures Customer Number and MWH Sales.[342] For the allocation of costs that are a function of two cost measures, the use of composite allocators is appropriate; however, rarely do two cost drivers (and four composite allocators) have an equal impact on the costs to be allocated. Thus, Delmarva's assumption that two cost measures have an equal impact on costs introduces another source of inaccuracy.

Delmarva admitted that no empirical studies exist to support its 50/50 split or averaging. Instead, this split was based on Mr. Tanos' personal experience in the industry.[343] Moreover, Mr. Tanos testified that for this rate case, Delmarva used the same basic cost of service model "submitted in PSC Docket No. 11-528 that formed the basis for the approved rate design in that case."[344] However, the Commission never approved a particular rate design structure in that docket.[345] In addition, Delmarva also took the liberty of incorporating four modifications to the COSS based on workshop initiatives from PSC Docket No. 09-414 even though the parties in that docket failed to agree on any modifications in particular. Specifically, Tanos agreed that the four initiatives introduced by Delmarva in this case regarding cost allocation, such as for weather normalized sales and revenue, have not yet been approved by the Commission[346] or even agreed

[340] Exh. 10 (Pavlovic) at 14 (citing Exhibit KRP-2, at 67-68).
[341] *Id.*
[342] *Id.*
[343] Tr. 945 to 946, 949.
[344] Exh. 8 (Tanos) at 7.
[345] PSC Order No. 8265 (December 18, 2012) specifically adopted the Hearing Examiners' Report, which noted as follows: "The Settling Parties are not asking the Commission to approve ratemaking treatment for any issues not specifically addressed in the Settlement." See Order No. 8265, p. 30, at ¶71.
[346] Tr. at 921-922

upon by the parties in PSC Docket No. 09-414 in any written document.[347] Tr. 919:8 to 920:6. According to him, these proposals were "being put before the Commission via this filing."[348]

B. The HE should reject Delmarva's proposed rate design and revenue requirement distribution because both proposals fail to align with cost-causative principles.

Delmarva incorrectly alleges that Staff witness Pavlovic recommended that the Commission accept Delmarva's proposed revenue allocation and rate structure, when, in fact, the opposite is true. [349] Dr. Pavlovic pointed out several times that the COSS fails to follow cost-causative principles in many respects.[350] In addition, he noted that relying on a faulty COSS will cause over-allocation of costs to a class (or under-allocation to a class), which in turn produces an understatement[351] of class return (or an over-statement of class return).[352] Even Delmarva's COSS witness, Mr. Tanos, acknowledged that if costs are over-allocated to one class, this will cause an understatement of class return. Moreover, Mr. Tanos also acknowledged and that an under-allocation will produce an over statement of that class return.[353]

Delmarva uses class rates of return as the basis to distribute its revenue requirement.[354] Delmarva also agrees that accurate demand allocation to the classes is required to determine class rate of return.[355] If the rate of return of a class is understated, the revenue requirement distribution will overstate that class' cost contribution (and vice versa for overstatements).[356] The rates for that class will then recover from such class more than its cost-causative share of the costs. Again, because Delmarva's COSS is, in fact, based on incorrect assumptions, the Hearing

[347] Tr. at 919-920.
[348] Tr. at 921-922.
[349] OB at 109.
[350] Exh. 10 (Pavlovic) at 5 and 18.
[351] An under-allocation of costs to a class will result in an overstatement of the class return.
[352] Exh. 10 (Pavlovic) at 13.
[353] Tr. at 933.
[354] Exh. 10 (Pavlovic) at 19; Tr. at 937.
[355] Tr. at 938.
[356] Exh. 10 (Pavlovic) at 13.

Examiner and the Commission should reject the resulting rate design and revenue requirement distribution proposals.

Given that the COSS possibly understates the residential class' ROR, using the UROR[357] to distribute the revenue requirement is a futile attempt. As Pavlovic pointed out (and Santacecilia acknowledged), there is no theoretical economic requirement that all classes produce the same ROR, which is the underlying principle for the UROR procedure.[358] Moreover, Delmarva proposes to place 65% of the proposed revenue requirement on the residential class (versus 60% in the current revenue distribution).[359] Delmarva's rate design also is, in itself, faulty. For more than half of the customer classes, Delmarva fails to use a billing component for demand. This is significant because demand is a major driver of distribution facilities costs.[360] Delmarva instead uses a volumetric billing component which is not a driver of distribution facilities costs.[361] Consequently, the proposed tariff charges for the RES, RSH, SGS-ND, and MGS service classifications do not reflect the actual costs incurred in providing service and hence violate the cost-causative principles. To counter this result, Delmarva claims that because the "appropriate demand data is not available," the current rate structure (of a customer charge and a volumetric delivery charge) should be maintained.[362] The Hearing Examiner should reject Delmarva's argument here because it is based on the incorrect assertion that demand data is unavailable when, in fact, such data is available to measure demand via the AMI meters.[363]

[357] "UROR" stands for Unitized Rate of Return.
[358] Exh. 10 (Pavlovic) at 19; Tr. at 882.
[359] Exh. 10 (Pavlovic) at 19.
[360] Exh. 10 (Pavlovic) at 21; (citing NARUC Manual at.89).
[361] Exh. 10 (Pavlovic) at 21; also Exh. 6 (Santacecilia) at 4-5.
[362] Exh. 6 (Santacecilia) at 5.
[363] AMI meters have been fully deployed to Delmarva's customers. Exh. 5 (Ziminsky) at 17. In addition, Delmarva has been collecting demand data from its AMI meters since August 29, 2013. Exh. 8 (Tanos) at 6.

Rate design determines a set of prices for each rate class designed to produce the allocated revenue requirements.[364] To achieve certain goals for rate structure, rate design must meet certain objectives. One of these objections is that rate design should produce a set of rates for each rate class that produces revenues that cover the cost of serving that class. Although class rate of return is an appropriate basis for developing class revenue requirement distribution, and given that accurate demand allocation to the Company's classes is required to determine class rate of return, Delmarva should undertake to develop demand allocators that more accurately reflect class cost responsibility for the demand-related facilities in Delmarva's distribution system.[365] In the end, though, Delmarva's rate design and revenue requirement distribution proposals fail to meet the cost-causative principles and should therefore be rejected by the Hearing Examiner and the Commission.

---

[364] Exh. 10 Pavlovic at 20-21.
[365] Exh. 10 (Pavlovic) at 15.

CONCLUSION

Based on the foregoing arguments and authorities, Staff respectfully requests the Hearing Examiner and this Commission to approve its proposed adjustments and reject the Delmarva adjustments that it has contested.

Respectfully submitted,

/s/ James McC. Geddes

James McC. Geddes (#690)
Ashby & Geddes
500 Delaware Avenue
P.O. Box 1150
Wilmington DE 19899
302-654-1888 ext. 230 (telephone)
302-438-9500 (cell phone)
302-654-2067 (fax)
jamesgeddes@mac.com

Julie M. Donoghue (#3748)
Deputy Attorney General
Delaware Department of Justice
820 N. French Street, 6th Floor
Wilmington, DE 19801
302-577-8348 (telephone)
jo.donoghue@state.de.us

Counsel to the Commission Staff.

Dated: January 21, 2014

A

APPENDIX A

David C. Parcell Cost of Capital Testimonies

Year	Utility	Jurisdiction	Case or Docket No.	Client
1998	United Water of Delaware	Delaware	98-98	Staff
2001	Artesian Water Co	Delaware	00-649	Staff
2001	Chesapeake Utilities Corp	Delaware	01-307	Staff
2002	Tidewater Utilities Co	Delaware	02-28	Staff
2002	Artesian Water Co	Delaware	02-109	Staff
2003	Conectiv Power Delivery	Delaware	03-127	Staff
2005	Delmarva Power & Light C	Delaware	05-304	Staff
2006	Tidewater Utilities	Delaware	06-145	Staff
2006	United Water Delaware	Delaware	06-174	Staff
2007	Delmarva Power & Light --	Delaware	06-284	Staff
2007	Chesapeake Utilities	Delaware	07-186	Staff
2008	Artesian Water	Delaware	08-96	Staff
2009	Artesian Water	Delaware	Regulation No. 51	Staff
2009	Tidewater Utilities	Delaware	09-29	Staff
2009	United Water Delaware	Delaware	09-60	Staff
2011	United Water of Delaware	Delaware	10-421	Staff
2011	Artesian Water	Delaware	11-207	Staff
2012	Delmarva Power & Light	Delaware	11-528	Staff
2013	Delmarva Power & Light (G	Delaware	12-546	Staff
2013	Delmarva Power & Light	Delaware	13-115	OPC

B

APPENDIX B

delmarva power
A PHI Company

800 King Street
Wilmington, DE 19801

P.O. Box 231
Wilmington, DE 19899-0231

302.429.3016 – Telephone
302.429.3801 – Facsimile

randall.griffin@pepcoholdings.com

Randall V. Griffin
Associate General Counsel

August 26, 2005

VIA E-MAIL and FIRST CLASS MAIL

Mr. Bruce H. Burcat
Executive Director
Delaware Public Service Commission
861 Silver Lake Boulevard
Cannon Building, Suite 100
Dover, DE 19904

Re: Informal Comments on Draft Proposed Regulations in Regulation Docket No. 50

Dear Mr. Burcat:

Attached are comments that have been prepared with respect to draft proposed regulations that Staff provided to us earlier this month. We certainly appreciate the opportunity to comment prior to the time when proposed regulations are officially published and, in that same spirit, we gladly participated in the workshop process that Staff used to explore these issues over the last several months. This letter is intended to highlight a few issues, including an issue regarding the workshop process itself.

First, I would note that there are a large number of issues that do not appear to be close to a consensus resolution and will require additional proceedings. I do not see any realistic possibility that this can be accomplished before the end of the year when the interim regulations expire. For that reason, Delmarva would suggest that the parties may wish to propose jointly to the Commission that the interim regulations be extended until superseded by whatever regulations are finalized out of this process.

Second, while Delmarva has not yet attempted to quantify the dollar impact of the proposed regulations, it is not difficult to see that the amounts involved could be many millions, even tens of millions of dollars. Requiring the Company to install certain types of equipment and directing that its vegetative management, inspections and maintenance of facilities be done in a particular way not only suggests micro-management, but would impose significant additional costs with no clear benefit. A congestion hours standard that has no cost-benefit criterion could require tens of millions in capital costs in an attempt to meet a standard that may be unobtainable in any event due to the actions of third parties.

Third, and related to the first point, Delmarva would request that the Staff seriously consider the possibility that no additional regulations are necessary and that the interim regulations could be repromulgated as final regulations. In support of that concept, Delmarva would note that its attached comments set forth customer satisfaction statistics, including statistics tied directly to reliability, which show customer satisfaction at relatively high levels and significantly up from 1999. It is certainly not clear to Delmarva that the workshop process identified any particular need suggesting that major changes, or even any changes, are needed to the interim regulations. Alternatively, but along the same lines, Staff may wish to consider the merits of focusing the rest of this proceeding on establishing a reasonable penalty/reward structure around the existing interim standards.

Fourth, with respect to the proposed regulations themselves, Delmarva's single largest issue is going to be the method by which the CAIDI and SAIFI statistics are set. Stripped of verbiage about how the standards were developed, the end proposal is that the standard for each year will be based solely on the prior three years of actual experience. That means that even a slightly "worse" statistic in year 4 relative to one of the years incorporated into the average may result in a violation of the statistic. E.g., the proposed regulations initially set the SAIFI standard at 1.80, but if the SAIFI results over the next few years were 1.74, 1.70, 1.60, and 1.69, the 1.69 statistic in Year 4 would violate the standard. It would be above the 1.68 average over the prior three years even though: 1) there was no single year that was above the initially set SAIFI standard of 1.80; 2) the 1.69 figure is better than the initially set SAIFI standard and two of the previous three years; and 3) that degree of variability is well within what would be expected given differences in weather, statistical variability in the failure of system components, and so on. Moreover, this structure creates a perverse incentive by enhancing the likelihood of future penalties if there is a particularly good performance in one year -- the 1.60 statistic from Year 3, almost guarantees that the utility will violate the standard in Years 5 and 6. The Company strongly urges Staff to reconsider its proposal and restore the use of a standard deviation band around a statistic. The interim regulations use a one year statistic and a 1.75 standard deviation. The Company has proposed the use of a 5-year average and a 1.75 standard deviation. No matter what the final result may be, however, it has to incorporate a standard deviation band of some reasonable size in order to avoid creating "violations" that are the result of weather and normal statistical variations.

Delmarva will also continue to oppose the imposition of a congestion hours standard. Congestion is simply not a reliability issue -- it is a pricing issue. The FERC fact finding investigation speaks to this point as well. Moreover, since congestion is only partially within Delmarva's control, it is inequitable to impose a standard that Delmarva would "violate" whenever other entities take actions in their own self-interest that cause an increase in congestion.

Other substantive issues are addressed in the attached comments, some of which will also be noted here in the context of a broader concern regarding the workshop process itself. Unlike the workshop process that led to the recent settlement in Docket No. 04-391, the workshop process here appears not to have moved much toward a consensus. Perhaps this can be seen best in the context of the proposal to create a standard regarding the percentages of customers to be restored within a defined period after a major event. This concept was first floated by a member of Staff during workshops held as part of the Hurricane Isabel proceeding. In that proceeding, the Company repeatedly explained that every major event has unique characteristics and it presented data to Staff to show that other utilities faced with major events have had outages with durations of two weeks or more affecting many customers. For that reason, the Company urged in those Hurricane Isabel workshops that no major event restoration standard be recommended. Notwithstanding the data provided to Staff, Staff continued to push for such standards and it became a litigated issue before the Hearing Examiner. The Hearing Examiner did not recommend and found no reason to pursue Staff's proposal for developing major event restoration standards. While the Commission subsequently directed the parties to continue to look at this issue, there was no directive that some standard was required to be developed, irrespective of the outcome of this review. In a workshop that covered this subject, Delmarva, DEC and representatives of the Local Union, spoke against having a major event restoration standard. In addition to the arguments presented in the Hurricane Isabel proceeding, Delmarva and the Union representatives identified a potential safety issue – no one would want to create a regulatory incentive for a utility to reduce in any way its emphasis on safety in order to meet some arbitrary percentage of customers restored in a certain period of time. While there appeared to be a consensus on this point at the workshop, the proposed regulations seemingly ignore this input and consensus to propose major event restoration standards.

While the foregoing is perhaps the clearest example, there are a number of other areas where it is difficult to discern that the workshop process has actually led to a proposal that reflects the views of the workshop participants. I do not believe that any participant other than the member of Staff leading the workshop has supported the intrusion of the Commission into the business practices of the utility in the form of telling a utility how often to do tree trimming and inspect facilities and what kinds of equipment should be installed on the system.

Last, but certainly not least, the Company continues to oppose in this and any other context proposals that are asymmetrical in creating potential penalties with no potential for rewards.

I hope that this letter highlights and clarifies some of the Company's key concerns that are discussed in the attached comments.

Respectfully submitted,

Randall V. Griffin

cc: Connie McDowell
James McC. Geddes
Janis Dillard
Robert Howatt
David Bloom
Arthur Padmore
Bo Shen
Bill Andrew
Cynthia Longobardi
David Rosenstein
Mike Dennis
John Citrolo
John Stutz
Ken Ellers
Kevin Neilson
Wayne Hudders
Paul Simon

DELMARVA POWER & LIGHT COMPANY
COMMENTS ON

STATE OF DELAWARE

DELAWARE PUBLIC SERVICE COMMISSION

Electric Service Reliability and Quality Standards

Staff Report

Version Received August 4, 2005

(August 26, 2005)

Contents

Summary

The process of determining electric service reliability and quality standards for Delaware customers began in 1999, and since that time there have been white papers, workshops, proposals, hearings, recommendations, orders, and interim standards. Throughout this process, Delmarva Power & Light (DPL) has been an active participant, because we believe reliability is a critical issue for our customers, employees, and shareholders. Like Staff, we believe that if reliability service and quality standards are to be established, they must be fair and equitable to the public and utilities. We received the Staff's latest reliability standards proposal on August 4, 2005. We have concluded that the standards proposed are **not** fair and equitable for the following reasons:

1. DPL is already meeting, and has met, the reliability expectations of our customers.
2. Staff has not provided a rationale for why a standard should be implemented.
3. Staff has not reflected many of the positions put forward by DPL during the workshops.
4. Staff has proposed that the Commission micromanage DPL's maintenance and inspection programs by mandating when and how a program is to operate.
5. Staff has recommended implementing technology without regard to the burden the cost of implementing that new technology may place on the public.
6. Staff has proposed implementing standards in areas where DPL has limited authority or control.
7. Staff has not addressed weather and other aspects of variability that are outside DPL's control.
8. Staff has proposed that the Commission be responsible for assessing penalties for violating the standards while being arbitrary with respect to the size, extent. and duration of the penalties
9. Staff has, with no discussion, eliminated the possible of DPL earning a reward for exceeding benchmarks.

DPL proposes, because of the unfair and inequitable nature of the standards, and because in many cases there is limited rationale supporting the creation of the standards, that current interim standards be extend through 2007.

Electric Service Reliability and Quality Standards

(August 4, 2005 Draft)

This section of DPL's commentary addresses specific issues within Staff's August 4, 2005, proposed Electric Service Reliability and Quality Standards. DPL raised these issues at the workshops, but, to a large extent DPL's comments appear to have had little effect on influencing Staff's proposals. However, based on the assumption that Staff wants feedback on the August 4, 2005, version of the proposed regulations, we have commented below on the following areas:

1. Why change?
2. Inconsistencies in Staff's papers over the last six years.
3. Rationale for SAIFI and CAIDI benchmarks
4. Rationale for Constrained Hours of Operation
5. Rationale for Enhanced Maintenance and Inspection requirements
6. Rationale for Establishing Restoration benchmarks
7. Rationale for Notification of and Reporting Major Events
8. Rationale for SCADA expenditures
9. Penalties and Rewards

<u>Why change?</u>
As noted in earlier parts of this commentary, the Commission began this regulatory process as a result of legislation regarding maintenance of levels of reliability. The Staff was asked to explore whether electric service reliability and quality standards are required. Interim standards were established in November 2003. As has been demonstrated in the section DPL Performance, DPL's performance has been maintained since 1999, customers appear to be satisfied with DPL's overall performance, and even more satisfied with DPL's reliability; therefore, DPL questions why the interim standards should not be made permanent.

In the proposed regulations, Staff identified two plausible reasons as to why the standards approved in November 2003 should change: a) to ensure that DPL provides service that is consistent with pre-restructuring service levels and b) to ensure DPL is in compliance with National Electrical Safety Code Standards and transmission operating policies and standards. Staff has never indicated that DPL was not in compliance with all appropriate standards; therefore, we assume b) is not a rationale for changing the interim standards. Similarly, electric service reliability and the customer's perception of that level of reliability is consistent with pre-restructuring levels; therefore, DPL meets the only other test put forward by Staff for proposing new standards.

<u>Inconsistencies in Staff's paper's over the last six years</u>
In the proposed August 4 regulations, Staff puts forward revised reliability standards (e.g. SAIFI) and adds a number of new standards (e.g., Major Event), but in so doing they are inconsistent with earlier positions. For example, in the minutes of the January 19 workshop "... penalties and rewards around the benchmark were an integral part of the

overall effort and would have to be taken into consideration when establishing benchmarks." Yet the August 4 draft establishes standards without any consideration of rewards. In its March 20, 2001, White Paper, Staff states, "How best to achieve compliance with the standards would be left to the discretion of the utility." Yet the August 4 draft establishes SCADA, Equipment, and Vegetation standards. Another example can also be taken from the March 20, 2001, White Paper where Staff states, "The Commission should allow the distribution companies to determine the appropriate level of tree trimming. It should not dictate tree trimming schedules, but should allow Staff's proposals to direct the utilities needs." Yet the August 4 proposal in Section G, paragraph 3) mandates inspection and trimming standards. Staff has not provided any rationale as to why it is proposing to make changes from its original March 20, 2001, recommendations.

Rationale for SAIFI, CAIDI and other reliability benchmarks

Staff has proposed a SAIFI benchmark of 1.8, and a CAIDI benchmark of 134 minutes for DPL is set so low that it virtually guarantees DPL will violate the standards every year that its annual CAIDI is even marginally more than the CAIDI standard. Staff also proposes that DPL report performance against these benchmarks for the current year and on a three-year rolling average. The rationale for the Staff benchmarks seems to be overly complicated to arrive at a simple average for the last three years (2002-2004) of performance. While Staff states that it arrived at these benchmarks by creating an OMS adjustment factor that is a ratio of DPL's five-year (1995-1999) average performance to its most recent three-year (2002-2004) average; the resulting OMS factor is then applied to the historic five-year performance. The resulting SAIFI (1.79) benchmark is no different than if Staff had merely calculated the average of the last three years' performance. While DPL agrees that there needs to be an adjustment factor applied to historic reliability performance for the introduction of a new OMS, Staff needs to provide a rationale for the approach it adopted. DPL also agrees that the benchmark needs to be based on more than one year's performance. Further, using a three-year average does not allow for normal variability in weather and other factors beyond DPL's control. There should be a minimum of five years of post OMS. Therefore, DPL has proposed using a five-year rolling average. As noted earlier, Staff has failed to incorporate any allowance for normal variability. DPL proposes that a band around the five-year rolling average benchmark be established. The band width should be +/- 1.75 standard deviations about the 5-year average.

Staff has based its benchmark determination on DPL's actual performance. DPL agrees with this approach, but as noted, DPL believes there should be five years of actual data (2002-2007). Therefore, DPL proposes that the interim standards be extended through 2007, and at that point a five-year rolling average standard be determined and used starting January 1, 2008.

DPL also wants to correct the definition of $CELID_8$ and $CEMI_8$ put forward by the Staff. $CELID_8$ represents the total number of customers that have experienced a cumulative total of more than 8 hours of outages. $CEMI_8$ is an index that reflects the total number of customers having 9 or more outages. Mathematically, this is given in the following equation[1]:

$$CEMI_8 = \frac{\text{Total number of customers that experienced more than 8 sustained interruptions}}{\text{Total number of customers served}}$$ $\frac{500}{300{,}000}$

Rationale for Constrained hours of Operation benchmarks

Staff proposes establishing a constrained hours of operation benchmark of 600 hours for DPL. DPL strongly opposes any constrained hours standard because:

1. Congestion is a pricing mechanism and not an issue of reliability; and
2. Congestion is only partly controllable by DPL. For example, if NRG closed down Indian River, congestion hours would likely increase significantly. This summer a change in the way PJM dispatches Chesapeake Commonwealth's Virginia unit appears to have affected the level of congestion on the peninsula.

Current provisions relating to congestion merely trigger a study to find a potential cost effective solution. This concept is totally absent from the approach, and proposes one which results in a violation for exceeding the standard. Throughout the workshops, DPL raised jurisdictional, definitional, and practical issues regarding the adoption of any constrained hours of operation standards. The Staff has not addressed these issues. For the reasons stated in the workshops and in prior discussions, DPL continues to believe that there should not be a standard for constrained hours of operation.

Rationale for Enhanced Maintenance and Inspection requirements

Staff introduced equipment and vegetation inspection and maintenance standards. The only rationale provided for these standards was, "Each EDC shall have an inspection and maintenance program designed to maintain delivery facilities' performance at an acceptable level." The Staff-proposed regulations then go on to state, "...The program shall be based on industry codes, national electric industry standards, manufacturer's recommendations, sound engineering judgment and past experience." DPL sees no reason for these standards since DPL has, since its inception, followed the criteria put forward by the Staff for making maintenance and inspection decisions. In addition—and specifically with reference to vegetation management—DPL has already been recognized by the Commission, Staff, and others for its outstanding vegetation management program. The Hurricane Isabel hearings included an extensive review of DPL's reliability-centered approach to vegetation management. Staff appears to have established vegetation management benchmarks with limited reference to DPL's existing practices, and without taking into consideration the potential cost to the public of implementing a two-year inspection and four-year trim cycle. DPL does not believe it is necessary to adopt any maintenance and inspection standards.

Rationale for Establishing Restoration benchmarks

Staff has introduced a number of requirements related to restoration. Staff has proposed that 95% of all customers experiencing a major outage be restored within three days, and

[1] IEEE 1366-2003, page 6.

100% within five days. Staff offers little rationale for why the 95% and 100% benchmarks have been chosen. In the workshops, Staff's presentations recognized that no two major events are the same, and that there is significant variability in weather-related events. Staff appears to have based its rationale for these metrics on an EEI survey which reviewed a number of major events between 1989 and 2003. The study was based on 44 voluntary responses and failed to include, for example, the Hydro Quebec ice storm of 1998, and Hurricane Andrew of 1992—both of which resulted in outage durations of greater than 30 days. The survey also did not take into consideration any of the four hurricanes to hit Florida in 2004. The range of outage duration for these four events was from 8 days to 15 days. DPL does not believe it is possible to establish major event restoration benchmarks, based on all the factors Staff has identified that contribute to no two events being the same. DPL also believes that creating arbitrary benchmarks for rates of restoration does not take into consideration a factor that is of concern to all parties—working safely!

Rationale for Notification of and Reporting Major Events

DPL continues to support the need to report major events to the Commission. As noted in DPL's response to Hurricane Isabel, major events are community events; therefore, the DPL should report to the Commission. Staff has correctly identified that the IEEE 1366 (2003) methodology results in more consistent and mathematically supportable reliability statistics. DPL will continue to use IEEE 1366 (2003) to report reliability statistics. But because the exclusion criteria vary from year to year and it is difficult to determine when the Commission should be notified regarding a major event based on actual performance, DPL will—for **major event reporting** purposes—report to the Commission when there is a sustained outage to more than 10% of DPL's customers during a 24-hour period.

Rationale for SCADA expenditures

Staff has proposed mandating the use of SCADA. Staff has incorporated the following definition into the proposed regulations:

"The SCADA system, at a minimum, shall consist of a remote monitoring and operating ability for all major transmission, substation and distribution circuit components integral to maintaining the reliability of the system. The system will have the ability to:

a. Monitor and record critical system load data and major equipment status;
b. Provide remote operational control over major equipment; and
c. Incorporate generally accepted utility industry safety and security standards."

Applying this requirement to all major substations could cost millions of dollars. Depending as to how one interprets the ambiguous terms (e.g., distribution circuit component), the costs could be multiples of that amount. DPL raised similar concerns over a Staff proposal that was similarly broad and similarly ambiguous in the February 10, 2005, workshop. While the words have changed, the problems of ambiguity and the lack of a cost benefit test remain. Staff still has not addressed whether the additional cost to be incurred provides a commensurate value to the customers. For reasons similar to those already articulated above in the Inconsistencies, and Maintenance and Inspection sections, DPL does not support the adoption of SCADA deployment standards.

Penalties and Rewards

Staff's proposal does not address rewards, and the penalties that could be applied are undefined as to size, when they would be applied, and on what basis the Commission would be able to determine such matters. As noted above and as stated at the January 19, 2005, workshop, establishing standards without knowing the philosophy, rationale, and methodologies for penalties and rewards means that an integral part of determining the standards is not addressed. In addition, not addressing normal variability through the use of upper and lower performance bands means that an integral part of determining standards has not been addressed. DPL continues to propose that if penalties are to be introduced, then equity dictates that DPL must have an opportunity to earn a reward. If penalties and rewards are not to be included, then it must be made clear that Staff is recommending only reporting standards.

Docket 50 History

As noted earlier, the process of establishing reliability standards for electric utilities operating in the State of Delaware began in 1999 with the opening of Docket 99-328 (Order No. 5480). Since then, the Staff has issued and revised a white paper concerning reliability standards, held workshops, and most recently, proposed Standards. The DPSC has issued a number of Orders related to Docket 50 and promulgated interim reliability standards with Order No. 6298 on November 4, 2003.

The March 20, 2001 Staff white paper entitled ***Electric Reliability White Paper***, and revised and released by Staff on May 1, 2002, primarily addressed generation and transmission capacity and load issues. For example, in Section IV of the white paper entitled **Possible Solutions to Address Reliability Concerns,** the topics discussed included the following: "Increasing Generation Capacity on the Peninsula", "Changing the PJM Rules", "Increasing Transmission Import Capability", and "Load Management". There is very little reference to reliability standards for the distribution system. The white paper contained fifteen recommendations, none of which dealt directly and explicitly with the establishment of distribution system reliability standards (See Appendix I). The only potential reference is incorporated in recommendation #1, but even here the Staff leave it to utility... *"How best to achieve compliance with the standards would be left to the discretion of the utility."* DPL agreed with this statement at the time and continues to agree with it today.

Since there is no reference to specific reliability standards, there is no reference to penalties or rewards associated with the performance of the distribution system. It is interesting to note that on page 26 of the white paper, the Staff stated, *"The Commission may want to consider supporting a proposal by the TOs at the FERC for performance-based ratemaking for transmission enhancements."* And within the same paragraph, it was noted, *"The baseline used in the PBR plan proposed by the TOs should be reviewed to determine its reasonableness. (All available historic data should be incorporated in the development of an appropriate baseline for any performance based ratemaking plan, so that the baseline is not artificially depressed. There is an incentive to reduce performance during a period in which a service provider is knowingly establishing a baseline against which future performance will be measured.)"*. From these statements DPL concludes that the Staff was supporting three critical issues in situations where penalties or incentives are applied. They are:

1. Before implementing any performance mechanism, a baseline has to be developed, based on a sufficient amount of historic data to insure the baseline reflects reality.
2. Both rewards and penalties should be incorporated in any mechanism designed to maintain a certain standard of performance.
3. It is acceptable for a utility to earn an incentive beyond its return on equity, should it perform above a baseline.

DPL agrees with the underlying thinking on which Staff recommendations were made in the white paper.

Also, as noted above, the process of determining an appropriate set on reliability standards continued and culminated in the creation of interim reliability standards in November 2003. In their order, the Commission accepted the recommendation of the Hearing Examiner. In summary, the Hearing Examiner recommended:

1. The establishment of interim reliability standards for DPL that were developed based on DPL's "distinct operating characteristics";
2. That the industry reliability indices System Average Interruption Frequency Index (SAIFI) and Customer Average Interruption Frequency Index (CAIDI) be adopted as the DPSC reliability standards;
3. That there be a band of 1.75 standard deviations for data availability;
4. That the SAIFI target should be 2.3 and the CAIDI target should be 141 minutes;
5. That the SAIFI and CAIDI targets not be used to penalize DPL;
6. That DPL submit annual Planning and Studies and Performance Reports;
7. That IEEE 1366, once adopted by IEEE, be used to determine SAIFI and CAIDI; and that
8. The interim reliability standards should apply through 2005.

The Hearing Examiner made no recommendations concerning Constrained Hours of Operation.

DPL agreed with, and accepted all of the Hearing Examiner's recommendations.

In late 2004, the Staff launched a series of workshops to begin the development of permanent reliability standards, to be implemented on January 1, 2006.

Summary of December 2004 – April 2005 Workshops

On November 19, 2004, the DPSC Staff informed the Public that a series of six workshops would be held between December 2004 and April 2005; the purpose of which was "to offer members of the public an opportunity to express their viewpoints" on reliability, as well as Staff and public utilities "where several issues had been identified as issues that could benefit from further discussion." The six workshops were structured as follows:

Day – Date – Time	Discussion Topics
Thursday December 16, 2004, 9:00 AM	Regulation overview Company performance General issues/comment
Wednesday January 19, 2005, 9:00 AM	Benchmark standards Service level minimums
Thursday February 10, 2005, 9:00 AM	Infrastructure adequacy Operating constraints
Wednesday March 2, 2005, 9:00 AM	Major event standards (storm & disaster response)
Thursday March 24, 2005, 9:00 AM	Generation interconnection Generation supply adequacy
Wednesday April 14, 2005, 9:00 AM	Reward/penalty structure Attachments Miscellaneous items

As noted earlier, DPL was an active participant on all workshops.

Each of the positions DPL put forward in the workshops has been summarized below:

1. <u>December 16, 2004 (Regulation Overview, Company Performance)</u>
   The primary purpose of this meeting was to launch the series of workshops and to review the history of Docket 50. Staff noted that the goal of the workshops was to create a proposed set of reliability standards regulations that were: "…fair and equitable regulations for the public and utilities". DPL was, and continues to be aligned with Staff's goal for the workshops and the regulations.

2. <u>January 19, 2005 (Benchmark Standards, Service Level Minimums)</u>
   This meeting focused on the reliability standards. Staff noted that "…penalties and rewards around the benchmark were an integral part of the overall effort and would have to be taken into consideration when establishing benchmarks". Staff also noted that they had "…arbitrarily made the three adjustments (from the interim standards) to arrive at new proposed benchmarks." The three arbitrary adjustments were: reduce the standard deviation from 1.75 to 1.0; OMS adjustment factors; and one uniform standard for both utilities (SAIFI 2.0 and CAIDI 120

minutes). In addition, the Forced Outage Rate (FOR) was reduced to no more than 0.1%. The Staff also proposed standards for vegetation management, and construction and maintenance practices.

While continuing to support the process and Staff's desire to have reporting requirements for reliability, DPL raised numerous concerns about the proposed benchmarks. DPL also expressed concerns as to how the benchmarks had been derived, because in some cases it appeared to be—as the Staff noted—arbitrary, and did not take into consideration the randomness of events that affect reliability. DPL proposed that the standards continue to be based on historical performance. DPL also proposed that customer satisfaction measures and complaints to the commission should possibly be taken into consideration in setting reliability targets.

3. February 10, 2005 (Infrastructure Adequacy, Operating Constraints)
At this meeting, DPL presented additional information concerning the standards. Specifically, DPL proposed that the interim regulations be made permanent with the following adjustments:
    - "Using post-OMS data only;
    - Performance targets for each utility based on historical post OMS data;
    - Performance targets based on a rolling five-year average;
    - Abandon Forced Outage Rate, Vegetation Mgmt, and New Construction metrics;
    - Maintain current CELID standard of 24 hours (with $25 penalty);
    - Consider inclusion of the proposed CEMI standard
    - Penalty or reward should be subject to a different standard;
    - Use 2006 as the test year;
    - Set targets and bands for reporting starting in 2007."

Staff proposed three measures related to the reliability of transmission infrastructure (hours of constrained operation; planning and construction —weather load criteria; and planning and construction—variable reserve margin). In addition, Staff proposed that DPL be mandated to implement a SCADA system to the substation level. DPL raised issues with respect to both the transmission infrastructure benchmarks and to the SCADA proposal. DPL noted that the implementation of SCADA to the substation level could be a significant expenditure for customers to bear.

4. March 2, 2005 (Major Event Standards)
DPL expanded on our objections to some of the specific proposals put forward by Staff at the February 10, 2005 workshop. DPL explained

that we already have in place processes and plans to address worst performing circuits, equipment failures, and pole inspections, and that annual maintenance plans are available to the DPSC. DPL concluded by stating "…adequate procedures were in place to monitor and review equipment failures and their impact. SCADA systems were well positioned to support restoration activities and current transmission system infrastructure exceeds load requirements and pre-restructuring capacity."

Staff went on to review their proposed standards for restoration, but did recognize that there were major differences between major events.

Staff proposed the following restoration standards:

- "80% of customers restored in five days;
- 120 customers restored per crew per day;
- 40 customers restored per responder per day; and
- 95% of customers restored in R days where R-function of damage or storm type or customers out."

Staff noted that a response measure tied to level of damage was probably best, but that there is no clear cut standard available. DPL noted that we already have effective restoration plans in place. Given the variability in major events, DPL saw no reason to establish restoration standards.

5. March 24, 2005 (General Interconnection, Generation Supply Adequacy)
Staff presented the history behind, and their rationale for proposing energy supply standards. The standards proposed were to "…maintain an average facility or source availability factor of at least 85%"; "…maintain an average facility or source forced outage rate of no more than 15%"; and to report performance annually. DPL could not support the proposals because the definition of "electric supplier" used by Staff was not consistent with the legislation; the Equivalent Availability Factor was incorrect; and a number needed to be worked on with PJM.

6. April 14, 2005 (Reward/Penalty Structure)
At this workshop, Staff "…noted that it had taken a worse case situation so that all parties would be aware of the potential impacts of the rewards/penalties to be discussed." Dr. Stutz, a DPSC consultant, reviewed the Rhode Island case and proposed, as was decided in Rhode Island, that a log normal approach to the outage frequency performance curve would lead to a more symmetrical balance between penalties and offsets. DPL reported that if the proposed benchmarks had been in place, DPL would have, for 2004, missed three of the eight standards. DPL reiterated the following adjustments:

- Use post OMS data;
- Use a 1.75 standard deviation to adjust for "normal noise/variability";
- Use a five-year rolling average;
- Maintain the current CELID standards;
- Introduce CEMI;
- Only introduce penalties if rewards are incorporated, and apply penalties to reinvestment in the system and rewards to non-revenue producing investments;
- Do not introduce Major Event, Forced Outage Rate, Constrained Hours of Operation, % Vegetation outages , % Equipment failure outages as standards; and
- The standards should begin in 2008.

Staff concluded the workshop process by indicating that a first draft of the final regulations would be available for comment in approximately 45 days.

Workshop Process

As noted earlier, the Staff has held informal workshops since the beginning of the Commissions exploration as to how electric reliability in Delaware should be addressed. As also noted earlier, DPL has been an active participant and has believed that the workshop process contributed to the understanding of issues, quality of discussion, and ultimately to improved regulatory processes. DPL went into the latest series of workshops believing—as Staff suggested at the initial workshop on December 16, 2005—that the purpose was to have a discussion of issues and create "fair and equitable regulations for the public and the utilities." After reviewing the Staff's August 4, 2005, proposal, DPL wonders whether Staff took any of our views into consideration when finalizing their recommendations. By proposing to mandate additional expenditures which may not contribute to a corresponding improvement in reliability, Staff appears to be asking the public to pay for system enhancements that are of questionable value (e.g., SCADA). Staff also appears to have discounted DPL's reliability and customer satisfaction performance since 2000. DPL believes the workshop process is an effective way of addressing issues and promoting understanding among the parties, but this is only true where all parties can conclude that their comments have had an effect on the outcome.

DPL Performance

Since the beginning of this process, the Commission, Staff, and DPL have all argued that reliability was very important to DPL's Delaware customers and to other stakeholders within the State. In support of this idea, studies by market research organizations and other utilities who have analyzed the relationship between reliability and customer satisfaction have concluded that where there is deterioration in reliability, there is a corresponding reduction in customer satisfaction. Therefore, in considering whether to mandate any standards beyond the interim standards established by Order 6298, it seems to us that DPL's performance and customer satisfaction should be taken into consideration. Below, both DPL's reliability performance and customer satisfaction are presented.

Prior to the implementation of the standards DPL presented data to the Staff demonstrating that the implementation of OMS could cause measured performance to vary by between 0% and 28% for SAIFI and 12% and 48% for CAIDI.

The following tables demonstrate that since 1999, DPL's performance has changed in line with that prediction.

DPL Reliability Performance

Reliability Performance (Excluding Major Events)							
		Pre-OMS			Post OMS		
		1999	2000	2001	2002	2003	2004
DPL	SAIFI	0.98	1.17	.94	1.83	2.15	1.64
	CAIDI	74	89	92	120	131	127
Delaware	SAIFI	1.17	1.01	0.84	1.88	1.87	1.61
	CAIDI	79	76	80	122	127	152

77%
1.79
133.7
1.01
74.3
261%

Reliability Performance (Excluding Major Events and Adjusted for OMS*)							
		Adjusted Pre-OMS			Post OMS		
		1999	2000	2001	2002	2003	2004
DPL	SAIFI	1.61	1.92	1.54	1.83	2.15	1.64
	CAIDI	147	178	184	120	131	127
Delaware	SAIFI	1.92	1.65	1.37	1.88	1.87	1.61
	CAIDI	158	152	161	122	127	152

- Adjustment factor of 1.638 applied to SAIFI and 2.003 applied to CAIDI for 1999, 2000 and 2001

61%

Because the "true" impact of OMS on the SAIFI and CAIDI statistics is impossible to determine an indirect approach is the best evidence of whether or not reliability has actually changed over time.

The survey below demonstrates that the customer is generally satisfied with DPL performance

Customer Satisfaction Performance (Market Strategies Inc.)

	ACE and DPL				
Positive ratings (6-10)	2000	2001	2002	2003	2004
Outcomes					
Overall Satisfaction Measures					
Overall satisfaction	65%	75%	75%	77%	80%
Reliability & Restoration Measures					
Providing reliable electric service	85	86	90	84	89
Having enough electrical capabilities to meet needs	79	78	82	71	76
	Delaware				
Positive ratings (6-10)	2000	2001	2002	2003	2004
Outcomes					
Overall Satisfaction Measures					
Overall satisfaction	58%	72%	74%	75%	78%
Reliability & Restoration Measures					
Providing reliable electric service	79	86	89	80	88
Having enough electrical capabilities to meet needs	73	80	84	78	85

Implementation Timetable

There continue to be many unresolved issues associated with the exploration and creation of electric service reliability and quality standards within Delaware. Given the normal regulatory process, DPL believes it will be difficult to implement revised standards by January 1, 2006. Therefore, DPL recommends that the interim standards be continued through 2007, and that any revised standards not be put in place until January 1, 2008.

Conclusion

As noted earlier, DPL appreciates the opportunity to comment on Staff's proposed regulations. DPL will continue to be an active participant in this process because we believe electric service reliability and quality are critical to our customers, our employees, and our shareholders. We went into Staff's workshop process believing that the purpose was to establish standards that were fair and equitable to the public and the utilities. We do not believe that the August proposed standards are fair and equitable. We have reached this conclusion because:

1. DPL is already meeting, and has met, the reliability expectations of our customers.
2. Staff has not provided a rationale for why a standard should be implemented.
3. Staff recommendations do not seem to reflect many of the positions put forward by DPL during the workshops.
4. Staff has proposed that the Commission micromanage DPL's maintenance and inspection programs by mandating when and how a program is to operate.
5. Staff has recommended implementing technology without regard to the burden the cost of implementing that new technology may place on the public.
6. Staff has proposed implementing standards in areas where DPL has limited authority or control.
7. Staff has not addressed weather and other aspects of variability that are outside DPL's control.
8. Staff has proposed that the Commission be responsible for assessing penalties for violating the standards while being arbitrary with respect to the size, extent, and duration of the penalties
9. Staff has, with no discussion, eliminated the possible of DPL earning a reward for exceeding benchmarks.

DPL continues to believe that given its historic performance, the Commission and the public are best and most cost-effectively served by having DPL report reliability performance on an annual basis, and by maintaining the customer service standards that are already in place.

Appendix I

Electric Reliability White Paper
Prepared by Staff of the Delaware Public Service Commission
March 20, 2001
(Revised May 1, 2002)

V. Conclusions and Recommendations

1. Based on Staff's findings for the potential for reliability degradation, adopt and implement the reliability standards and reporting requirements as proposed and modified in Regulation Docket 50. How best to achieve compliance with the standards would be left to the discretion of the utility.

2. The Commission should allow the distribution companies to determine the appropriate level of tree trimming required. It should not dictate tree trimming schedules, but should allow Staff's proposed standards to direct the utilities' needs. Nevertheless, the utilities should use their best efforts to take aesthetics into account when performing tree trimming.

3. Staff should continue to take an active role in the transmission planning process and work with PJM to evaluate the effectiveness of the transmission planning process and the congestion management system[2].

4. Staff should take an active role to ensure that the transmission planning process specifically considers transmission adequacy and reliability performance in load

---

[2] Some consider transmission congestion to be a reliability issue as well as an economic problem. For example, in a recently proposed amendment to Senate Bill 517, the following definition of transmission congestion was provided: "…an operating condition on the transmission system of a regional transmission organization that, if not managed, may cause—"(i) the overload of the transmission system elements; "(ii) depressed voltage; or "(iii) system instability."

pockets. The RTEPP should include provisions for identifying constraints on the transmission system that affect reliability of service to specific areas but that may not have triggered a supply response and/or enhancement or interconnection request due to other constraints (such as lack of adequate gas supply on the Peninsula). Staff should support efforts at PJM's Regional Transmission Expansion Planning Program to identify a mechanism that would provide for transmission enhancements for economic purposes.

5. The Commission may want to consider supporting a proposal by the TOs at the FERC for performance-based ratemaking for transmission enhancements. Data used in considering the necessity and location of such enhancements should be of sufficient specificity to permit an assessment of the adequacy of transmission service to the Peninsula and other load pockets. If data are collected on a transmission system-wide basis, transmission service in a load pocket may not be detected or adequately monitored. The baseline used in the PBR plan proposed by the TOs should be reviewed to determine its reasonableness. (All available historic data should be incorporated in the development of an appropriate baseline for any performance based ratemaking plan, so that the baseline is not artificially depressed. There is an incentive to reduce performance during a period in which a service provider is knowingly establishing a baseline against which future performance will be measured.) Finally, attention should be paid to the conflicting interests that exist for companies that own both constrained transmission and high cost generation in a load pocket. Any incentives should be carefully considered for their potential impact on a company's participation in the RTEPP or other transmission decisions.

6. *The Commission should work with other state agencies and other states to develop policies that would increase the price responsiveness of demand. Competition is a dynamic process between supply and demand. Most proposals target the supply side, but demand is also critical. A successful load response program would improve reliability as it improves economics.*

7. *Staff and the Commission should examine existing load management tariffs and customer contracts to ensure that they are structured to realize the full potential of these "negative" resources. EDCs should negotiate with their customers taking service under these tariffs to try to reduce any limitations on the duration, frequency and notice requirements of interruptions allowed under these tariffs, if needed and appropriate.*

8. *Staff, DEC, Conectiv and PJM should work together to ensure that the data used in system planning are as accurate as possible.*

9. *The Commission should encourage Delaware, Maryland and Virginia to work together to eliminate any entry barriers to construction of generation, transmission and distribution infrastructure. The appropriate state agencies should examine such barriers as siting, environmental regulations, and limited natural gas deliverability. They should also consider implementing tax and financing strategies to provide incentives for construction of new infrastructure, development of energy efficiency programs and/or development of new technologies.*

10. *The Commission should direct the EDCs to identify constraints on their transmission*[3] *systems that affect reliability of service or impose congestion charges in*

[3] The transmission facilities referred to here mean facilities that operate at voltages consistent with those defined in Title 26 §1001of the Delaware Code and should include all such facilities on the Peninsula, including facilities located in Maryland and Virginia.

specific areas of the Peninsula. The modeling used to identify the constraints should reflect the more conservative 90/10 weather normalized peak forecast methodology Such forecasts may be considered in order to understand how the system operates under more severe conditions. The EDCs should determine and report the most effective methods of relieving these constraints or eliminating congestion charges. Factors considered in making this determination should include economic, environmental and other relevant impacts.

11. The Commission should direct the EDCs to forecast the non-weather-normalized peak load for each distribution feeder and use such feeder load forecasts, with and without application of a historical diversity factor, to check the loading of the distribution substation transformers and distribution substation supply circuits that feed them. The loading of equipment under normal conditions is studied by comparing the load being carried by each feeder, distribution substation transformer, and distribution substation supply circuit with their normal equipment ratings with all facilities in service. The loading of substation equipment under operating contingencies should be studied by comparing the load being carried by each distribution substation transformer and each distribution substation supply circuit with their emergency equipment ratings in different study scenarios, each with one distribution substation transformer or one distribution substation supply circuit out of service.[4]

12. The Governor's State Energy Plan should be fully supported at both the task force and working group levels.

[4] Loading on distribution feeders is sometimes planned such that the feeder, operating under an emergency rating, can pick up a portion of the load from an adjacent feeder through the use of ties between the feeders out in the field.

13. The funds that have been collected from the "environmental incentive" assessment that are not already being used for rebates for photovoltaics and solar hot water heaters should be used to develop energy efficiency programs, such as: (1) the purchase of interval meters for residential customers so that they can participate in economic load management plans; (2) the providing of incentives to purchase and use energy efficient products; and (3) the development and use of environmentally sound energy efficient resources.

14. Delaware, Virginia and Maryland should develop a comprehensive energy policy for the Peninsula. The first step in this process should be the evaluation and determination of the most feasible and cost-effective energy efficiency, demand side, and distributed generation strategies. The next step would then be to determine how these strategies can and should be financed. Once developed, this policy could be used by DEDO to determine the most appropriate use of the funds collected through the environmental incentive assessment.

15. Staff recommends that each utility and PJM evaluate the usefulness of probabilistic analyses as a tool to examine its transmission system and, if appropriate, incorporate it into its transmission adequacy evaluations. However, Staff's reliability index recommendations contained in the reliability standards and reporting requirements in Regulation Docket 50 published by the Commission are designed to motivate electric utilities to perform at a predetermined minimum reliability level. This performance-based approach allows flexibility and puts the burden of determining the appropriate action on the utility. This approach further allows the Commission and Staff to evaluate the utilities' *performance after the fact based on measurable criteria without dictating the utilities' actions to meet the requirements or its transmission evaluation methods.*

Appendix II

Report of the Hearing Examiner
Robert P. Haynes
November 5, 2003

Discussion

"16. The performance standards were based upon DP&L's and DEC's pre-restructuring levels of performance, as adjusted for a 1.75 standard deviation for data variability and the change to a computerized record keeping known as an outage management system ("OMS"). The interim standards in the proposed rules are acceptable to both utilities, and are based upon recognized industry indices, namely, the System Average Interruption Frequency Index ("SAIFI") and the Customer Average Interruption Duration Index ("CAIDI").

17. Under the proposed rules' performance standards, DP&L would have a SAIFI of 2.3 times, or a customer average outage of 2.3 times per reporting period. DP&L's CAIDI standard would be 141 minutes, which means that an average outage would last 141 minutes. DEC's SAIFI would be 4.6 times and its CAIDI would be 173 minutes. The proposed rules' reporting periods are annually and a rolling three-year average. Both utilities will have an average 'Forced Outage Rate' limit of one percent of a facility's time in operation. These standards are interim and shall apply through 2005. I find that the performance standards are reasonable, particularly as the utilities accepted them.

18. The proposed rules' performance standards are expressly not to be used to penalize the utilities for any non-compliance. I agree that this is prudent since there are many uncertainties in the change from a manual reporting system to an OMS, as discussed later in this report. The proposed rules also remove from the performance standards' calculations any outage data from a "major event," as defined by the industry. Again, this is appropriate insofar as a major event could distort the data, which is designed to measure reliability under normal operations. Information on major event outages will still be reported to the Commission.

19. The proposed rules will require the utilities to submit annually a Planning and Studies Report and a Performance Report. These reports are to detail the utilities' plans to improve their performance and how they performed in the historic reporting periods. In addition, the utilities are to notify the Commission of a major event within thirty-six hours and submit a Major Event Report within fifteen days afterwards. A major event is defined by the accepted industry standard definition set forth in The Institute of Electrical and Electronics Engineers, Inc. ("I.E.E.E") Standard 1366.

20. In addition, the proposed rules will require that the electric utilities install an outage management system ("OMS"), which is defined "as a software system that provides database information to effectively manage service interruptions and minimize customer outage times." The record indicates that DP&L has an OMS that already is in operation; while DEC's OMS should be in operation by the time the proposed rules go into effect as regulations."

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF DELAWARE

IN THE MATTER OF THE APPLICATION OF DELMARVA POWER & LIGHT COMPANY FOR AN INCREASE IN ELECTRIC BASE RATES (FILED MARCH 22, 2013)	))))	PSC DOCKET NO. 13-115

CERTIFICATE OF SERVICE

I hereby certify that on January 23, 2014, I caused the attached **STAFF'S POST-HEARING BRIEF TO THE HEARING EXAMINER** to be served upon the Commission's Secretary and all parties on the attached service list in the manner indicated thereon.

Dated: January 23, 2014

/s/ James McC. Geddes

James McC. Geddes (#690)
Ashby & Geddes
500 Delaware Avenue
P.O. Box 1150
Wilmington DE 19899
302-438-9500 (cell phone)
jamesgeddes@mac.com

Julie M. Donoghue (#3748)
Deputy Attorney General
Delaware Department of Justice
820 North French Street, 6th Floor
Wilmington, DE 19801
302-577-8348 (telephone)
jo.donoghue@state.de.us

Attachments: Staff and the DPA's Petition for Interlocutory Appeal and exhibits
Service List – 1-17-14

SERVICE LIST
DP&L ELECTRIC BASE RATE CASE
PSC DOCKET No. 13-115
As of January 2, 2014

Mark Lawrence
Hearing Examiner
Delaware Public Service Commission
861 Silver Lake Boulevard, Suite 100
Dover, DE 19904
Tel: 302-736-7540
Fax: 302-739-4849
Email: mark.lawrence@state.de.us

James McC. Geddes, Esquire
Ashby & Geddes
500 Delaware Avenue, Suite 800
P.O. Box 1150
Wilmington, DE 19899
Tel: 302-654-1888
Fax: 302-654-2067
E-mail: jgeddes@ashby-geddes.com
jamesgeddes@mac.com

Amy Woodward
Public Utilities Analyst
Delaware Public Service Commission
861 Silver Lake Boulevard, Suite 100
Dover, DE 19904
Tel: 302-736-7566
Fax: 302-739-4849
Email: amy.woodward@state.de.us

Lisa Driggins
Public Utilities Analyst
Delaware Public Service Commission
861 Silver Lake Boulevard, Suite 100
Dover, DE 19904
Tel: 302-736-7550
Fax: 302-739-4849
Email: lisa.driggins@state.de.us

Robert J. Howatt
Executive Director
Delaware Public Service Commission
861 Silver Lake Blvd, Suite 100
Dover, DE 19904
Tel: 302-736-7516
Fax: 302-739-4849
Email: robert.howatt@state.de.us

Julie "Jo" Donoghue, Esq.
Deputy Attorney General
Delaware Department of Justice
c/o Public Service Commission
861 Silver Lake Blvd, Suite 100
Dover, DE 19904
Tel: 302-736-7558 (Dover)
Tel: 302-577-8348 (Wilmington)
Fax: 302-739-4849 (Dover)
Email: jo.donoghue@state.de.us

Janis Dillard
Deputy Director
Delaware Public Service Commission
861 Silver Lake Blvd, Suite 100
Dover, DE 19904
Tel: 302-736-7542
Fax: 302-739-4849
Email: janis.dillard@state.de.us

Kathleen "Kitty" Makowski, Esq.
Deputy Attorney General
Delaware Department of Justice
c/o Public Service Commission
861 Silver Lake Blvd., Suite 100
Dover, DE 19904
Tel: 302-736-7510
Fax: 302-739-4849
Email: kathleen.makowski@state.de.us

SERVICE LIST
DP&L ELECTRIC BASE RATE CASE
PSC DOCKET No. 13-115
As of September 4, 2013

Patricia Gannon
Public Utilities Analyst
Delaware Public Service Commission
861 Silver Lake Boulevard, Suite 100
Dover, DE 19904
Tel: 302-736-7552
Fax: 302-739-4849
Email: patricia.gannon@state.de.us

Todd Goodman, Esq.
Associate General Counsel
Pepco Holdings, Inc. Legal Services
500 North Wakefield Drive
Mail Stop 92 DC 42
Newark, DE 19702
Tel: 302-429-3786
Fax: 302-429-3801
Email: todd.goodman@pepcoholdings.com

David Bonar
Public Advocate
Division of the Public Advocate
820 North French Street, 4th Floor
Wilmington, DE 19801
Tel: 302-577-5080
Fax: 302-577-3297
E-mail: david.bonar@state.de.us

Pamela J. Scott, Esq.
Associate General Counsel
Pepco Holdings, Inc. Legal Services
500 North Wakefield Drive
Mail Stop 92 DC 42
Newark, DE 19702
Tel: 302-429-3143
Fax: 302-429-3801
Email: pjscott@pepcoholdings.com

Ruth Ann Price
Deputy Public Advocate
Division of the Public Advocate
820 North French Street, 4th Floor
Wilmington, DE 19801
Tel: 302-577-5014
Fax: 302-577-3297
Email: ruth.price@state.de.us

Todd A. Coomes, Esq.
Richards, Layton & Finger, P.A.
One Rodney Square
920 North King Street
Wilmington, Delaware 19801
Tel: 302-651-7700
Fax: 302-651-7701
E-mail: Coomes@RLF.com

Regina Iorii, Esq.
Deputy Attorney General
Division of the Public Advocate
820 North French Street
Wilmington, DE 19801
Tel: 302-577-8159
Fax: 302-577-3297
Email: regina.iorii@state.de.us

Jay C. Ziminsky
Finance Manger
Pepco Holdings, Inc.
P.O. Box 9239
Mailstop 79NC59
Newark, DE 19714-9239
Tel: 302-454-4626
Fax: 302-283-6090
E-mail: jay.ziminsky@pepcoholdings.com

SERVICE LIST
DP&L ELECTRIC BASE RATE CASE
PSC DOCKET No. 13-115
As of September 4, 2013

Andrea B. Maucher
Division of the Public Advocate
John G. Townsend Building
401 Federal Street, Suite 3 (SOS)
Dover, DE 19901
Phone: (302) 857-4620
Fax: (302) 739-4111
Email: andrea.maucher@state.de.us

Heather G. Hall
Delmarva Power & Light Company
Regulatory Affairs
P.O. Box 9239
Mailstop 79NC59
Newark, DE 19714-9239
Tel: 302-454-4828
Fax: 302-454-4440
E-mail: heather.hall@pepcoholdings.com

Pamela Long
Delmarva Power & Light Company
Regulatory Affairs
P.O. Box 9239
Mailstop 79NC59
Newark, DE 19714-9239
Tel: 302-454-
Fax: 302-454-4440
E-mail: pamela.long@pepcoholdings.com

Intervenors:

David T. Stevenson
Director, Center for Energy Competitiveness
Caesar Rodney Institute
P.O. Box 795
Dover, DE 19903
Tele: (302) 236-2050
Fax: (302) 645-9017
Email: davidstevenson@caesarrodney.org

Consultants:

DPA/Attorney General:

Andrea C. Crane
Benjamin D. Cotton
The Columbia Group, Inc.
P.O. Box 810
Georgetown, CT 06829
Phone: (203) 438-2999
Fax: (203) 894-3274
E-mail: ctcolumbia@aol.com

Courier Delivery:
90 Grove Street, Suite 200
Ridgefield, CT 06877

Lane Kollen
570 Colonial Park Drive, Ste. 305
Roswell, GA 30075

SERVICE LIST
DP&L ELECTRIC BASE RATE CASE
PSC DOCKET No. 13-115
As of September 4, 2013

Thomas G. Noyes
Division of Energy & Climate
Delaware Department of Natural Resources and Environmental Control
1203 College Park Drive, Suite 101
Dover, DE, 19904
Tel: 302-735-3356
Fax: 302-739-1840
E-mail: thomas.noyes@state.de.us

Ralph K. Durstein III
Deputy Attorney General
Carvel State Office Building
820 N. French St.
Wilmington, DE 19801
Tel: 302-577-8510
Fax: 302-577-5866
E-mail: ralph.durstein@state.de.us

Delaware Energy Users Group (DEUG)
Michael J. Quinan, Esquire
Christian & Barton, L.L.P.
909 E. Main Street, Ste. 1200
Richmond, VA 23219
Tel: 804-697-4149
Fax: 804-697-6149
E-mail: mquinan@cblaw.com

Phone: 770-992-2027
Fax: 770-992-0806
E-mail: lkollen@jkenn.com

David E. Dismukes, Ph.D
Acadian Consulting Group
5800 One Perkins Place, Ste. 5-F
Baton Rouge, LA 70808
Phone: (225) 769-2603
Fax: (225) 769-2608
E-mail: daviddismukes@acadianconsulting.com
Electronic Copies Only:
Kim Dismukes
kimdismukes@acadianconsulting.com
Alex Aguila
alexguila@acadianconsulting.com

Lane Kollen
570 Colonial Park Drive, Suite 305
Roswell, GA 30075
Tel: 770-992-2027
Fax: 770-992-806
E-mail: lkollen@jkenn.com

Staff:

David C. Parcell
Technical Associates, Inc.
9030 Stony Point Parkway, Ste. 580
Richmond, VA 23235
Phone: (804) 644-4000
Fax: (804) 272-3598
E-mail: parcelld@tai-econ.com

David Peterson
Chesapeake Regulatory Consultants
10351 S. Maryland Blvd., Ste. 202
Dunkirk, MD 20754
Phone: 410-286-0503
E-mail: davep@chesapeake.net

Stephanie Vavro, Principal
Silverpoint Consulting LLC
1519 Whispering Woods Circle

SERVICE LIST
DP&L ELECTRIC BASE RATE CASE
PSC DOCKET No. 13-115
As of September 4, 2013

Allentown, PA 18106
Phone: 610-530-7711
E-mail: vavro@silverpointconsulting.com

Gary B. Cohen
GBC Consulting
221 Hoyer Court
Wilmington, DE 19803
Tel: 302-529-7090
E-mail: garybcohen@aol.com
Michael J. Majoros, Jr.
Dr. Karl Pavlovic
Mitch Semanik
Snavely King Majoros O'Connor & Lee
8100 Professional Place, Ste. 306
Landover, MD 20785
Tel: 202-371-9153
Fax: 202-842-4966
E-mail: mmajoros@snavely-king.com
kpavlovic@snavely-king.com
msemanik @snavely-king.com